

CHAPTER 2

DESCRIPTION OF EQUIPMENT

SECTION I. BOILERS AND HEAT EXCHANGERS

2-1. BOILER CLASSIFICATIONS.

There are a few fundamental types of boilers and many variations of each type. Boilers are generally classified according to the relative position of combustion gases and water as either fire tube or water tube. Boilers are also classified by the form of energy produced; low or high pressure steam; low, medium, or high temperature water. Other methods of classifying boilers are listed below.

- Type of Water Circulation - natural circulation, forced circulation.
- Type of Steam Produced - saturated, superheated.
- Method of Assembly - package, modular, field erected.
- Type of Use - stationary, marine, power, heating.
- Type of Fuel - coal, oil, gas.
- Method of Combustion - spreader stoker, fluidized bed, pulverized coal.
- Boiler Capacity - Up to 20,700 pounds per hour (up to 600 horsepower) for fire tube boilers; up to 10,000,000 pounds per hour for water tube boilers; up to 200 million Btu per hour for hot water boilers.

2-2. BOILER DESIGN REQUIREMENTS.

A boiler must meet the following requirements:

- Operational safety.
- Generation of clean steam or hot water at the desired rate, pressure, and temperature.
- Economy of operation and maintenance.
- Conformance to applicable codes.

A set of rules for the construction and operation of boilers, known as the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, has been widely adopted by insurance underwriters and government agencies. Section I of the Code contains requirements for power boilers including methods of construction and installation, materials to be used, design, accessories, and inspection. Section IV of the Code contains requirements for heating boilers. Low pressure steam boilers and low temperature water boilers are classified as heating boilers. Section VI of the Code provides "Recommended Rules for Care and Operation of Heating Boilers" and Section VII provides "Recommended Rules for Care of Power Boilers." Other sections of the Code provide material specifications, nuclear equipment requirements, inspection requirements, and welding qualifications. To meet the above listed requirements, a boiler must have the following

characteristics:

- Adequate water or steam capacity.
- Properly sized steam/water separators for steam boilers.
- Rapid, positive, and regular water circulation.
- Heating surfaces which are easy to clean on both water and gas sides.
- Parts which are accessible for inspection and repair.
- Correct amount and proper arrangement of heating surface.
- A furnace of proper size and shape for efficient combustion and for directing the flow of gases for efficient heat transfer.

2-3. FABRICATION.

All boilers, superheaters, economizers, and other pressure parts must be built using materials and construction methods specified by the applicable Code sections. Repairs to boilers must also be made in accordance with Code requirements. Equipment built and inspected in accordance with the Code must have an ASME stamp. An "H" in a cloverleaf is stamped on heating boilers. An "S" in a cloverleaf is stamped on power boilers.

a. Drums, Shells, Headers. Boiler drums, shells, or headers are used to collect steam or hot water generated in the boiler and distribute it as necessary within the boiler tubes. These components must be strong enough to contain the steam or hot water that is generated and to mechanically hold the boiler tubes as they expand and contract with changes in temperature. The shells of fire tube boilers may be reinforced by the use of stays to hold the boiler heads in place. These components are generally fabricated with welded seams and connections. Riveted seams are no longer used, although many old riveted boilers are still in operation.

b. Boiler Tubes. Boiler tubes carry water, steam, or flue gases through the boiler. Boiler tubes are installed by expanding or welding them into seats in the drums or headers. The expander tool consists of a tapered pin which fits into a cage containing several small rollers. A different size expander is required for each size tube. During installation, the expander is slipped into the end of the tube and the tapered pin is pushed into the cage until the rollers are against the tube walls. Then the pin is turned with a wrench or motor, forcing the rollers out against the tube, and simultaneously moving the cage into the

tube. This action distorts and stretches the tube, forcing it to make a tight seal against the tube sheet. The expander often has a stop which helps prevent overexpanding, as shown in figure 2-1. Boiler tubes are installed with ends projecting slightly beyond the tube sheets. Projecting ends are flared slightly in water tube boilers and allowed to remain because they are surrounded and cooled by water or steam. Since tube ends of a fire tube boiler are surrounded by hot gases, they would soon burn off if allowed to project. They are therefore beaded and hammered until flat against the tube sheet. This process also increases the holding power of the tube. It must, however, be performed carefully to avoid injuring the tube. Figure 2-2 illustrates flared and beaded tubes.

c. Baffles. Baffles are thin walls or partitions installed in water tube boilers to direct the flow of gases over the heating surface in the desired manner. The number and position of baffles have a marked effect on boiler efficiency. A leaking or missing baffle permits gases to short-circuit through the boilers. Heat which should have been absorbed by the water is then dissipated and lost. With a leaking baffle, tubes may be damaged by the "blow-torch" action of the flame or hot gas sweeping across the tube at high velocity, especially if the leak is in or near the furnace. Baffles may be made of iron castings, sheet-metal strips, brick, tile, or plastic refractory. Provision must be made to permit movement between baffle and setting walls while still maintaining a gas-tight seal. Iron castings are made in long, narrow sections to fit in the tube lanes and around the tubes. They can be installed only while the boiler is being erected or assembled, and their use is limited by the temperatures which they can withstand. Sheet-metal strips are formed to fit around the tubes and are easily installed after tubes are in the boiler. Their primary uses are to help distribute flue gas within a pass and to maintain proper tube spacing, rather than to function as baffles between adjacent passes. This type baffle cannot be used in the high-temperature areas of the boiler. Brick or tile baffles, made of specially shaped forms which fit between and around the tubes, can be installed after the boiler has been erected and can be used in any area of the boiler. Castable plastic refractory baffles are usually installed by building a form and pouring the refractory like concrete. The forms are then removed after the refractory has set. This type of baffle can be used at any location in the boiler and, if properly designed, can remain gas-tight for long periods. It may be used to repair or replace other types of baffles.

2-4. FIRE TUBE BOILERS.

Many of the first steam boilers produced were designed with the products of combustion passing inside the tubes. Fire tube boiler design has developed primarily in the

direction of the Scotch-type boiler shown in figure 2-3. The Scotch boiler is shop-fabricated and is capable of supplying saturated steam at pressures below 250 psig at capacities below 20,000 lb/hr. At pressures above 250 psig, the natural circulation of water and steam in this design is not adequate for good heat transfer. At capacities above 20,000 lb/hr the shell diameter becomes too large to be economical. Scotch boilers come in two, three, and four gas pass designs, as illustrated in figure 2-4. With more gas passes and more heat transfer surface, boiler exit gas temperatures are lower and efficiencies higher. Wet-back construction in a Scotch boiler means that a water wall is provided at the outlet of the first pass or furnace. Wet-back construction reduces the high maintenance costs often associated with dry-back designs. Scotch-type fire tube boilers can effectively fire natural gas and fuel oils. Coal is a less desirable fuel because the fire tubes are not easily cleaned and ash removal is restricted. Advantages of the Scotch boiler include the ability to respond to rapid load swings due to the large volume of stored water/steam in the shell, low initial cost, low maintenance costs, and general ease of control. Disadvantages include the difficulty of producing superheated steam and pressure and capacity limitations. Scotch boilers are also used to produce low temperature water. The other common type of fire tube boiler is the horizontal return tubular (HRT) design, illustrated in figure 2-5. The firebox in this type of boiler permits the burning of coal using stokers or fluidized beds.

2-5. WATER TUBE BOILERS.

Water tube boilers were developed for a variety of reasons, including the need for higher pressures, higher capacities, superheated steam, faster response to load changes, and increased safety due to the reduced water volume. Water tube boilers have water inside the tube and the flue gases on the outside. The early straight-tube design boilers were replaced with today's bent-tube designs to increase the amount of available heat transfer surface, solve mechanical problems, and general economic reasons. Figure 2-6 illustrates a four-drum boiler with a water-cooled back wall. The bottom drum is called a mud drum because of the tendency of boiler sludge to collect in this low area. The upper drums are called steam drums. Water enters the top rear drum, passes through the tubes to the bottom drum, and then up through the tubes to the two front drums. A mixture of steam and water is discharged into these drums; steam returns to the top rear drum through the upper row of tubes while water travels through tubes in the lower rows. Steam is removed near the top of the rear drum by a dry pipe extending across the drum, and is discharged through the steam outlet header. The baffles are arranged to encourage flue gas flow over all the boiler

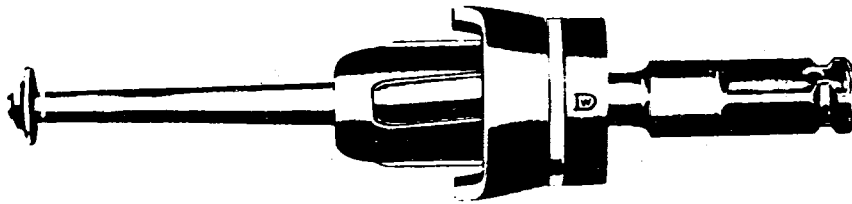
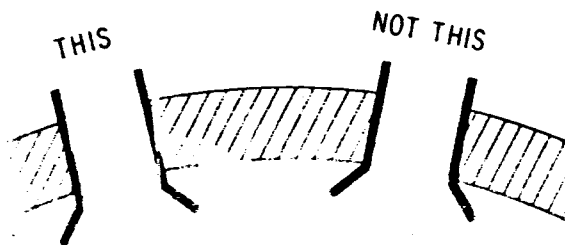
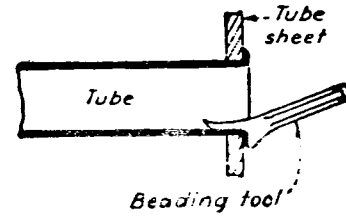


FIGURE 2-1. TUBE EXPANDER



FLARED TUBE



BEADED TUBE

FIGURE 2-2. FLARED AND BEADED TUBES

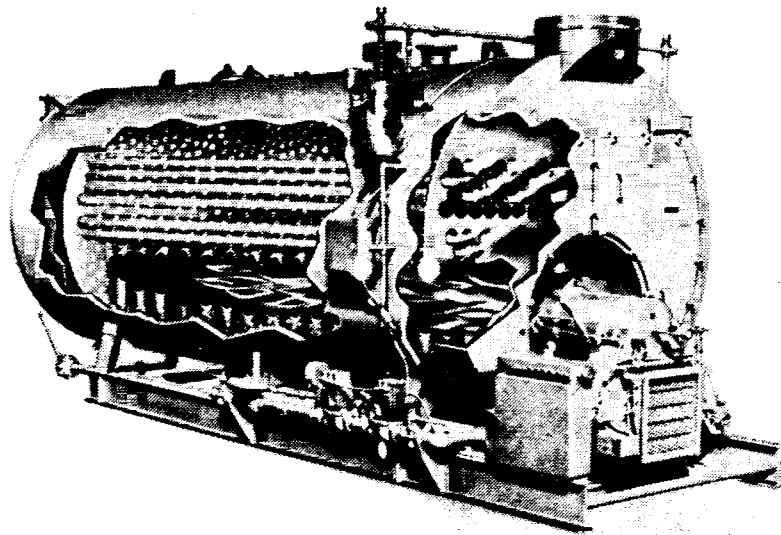
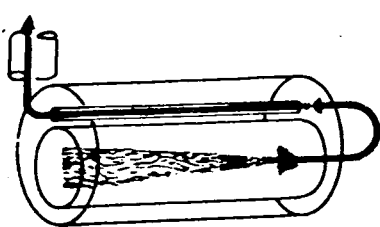
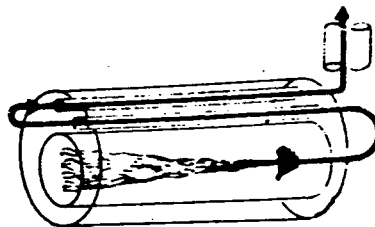


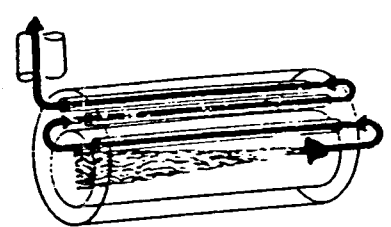
FIGURE 2-3. SCOTCH BOILER



2 PASS



3 PASS



4 PASS

FIGURE 2-4. TWO, THREE, AND FOUR PASS
SCOTCH BOILER DESIGNS

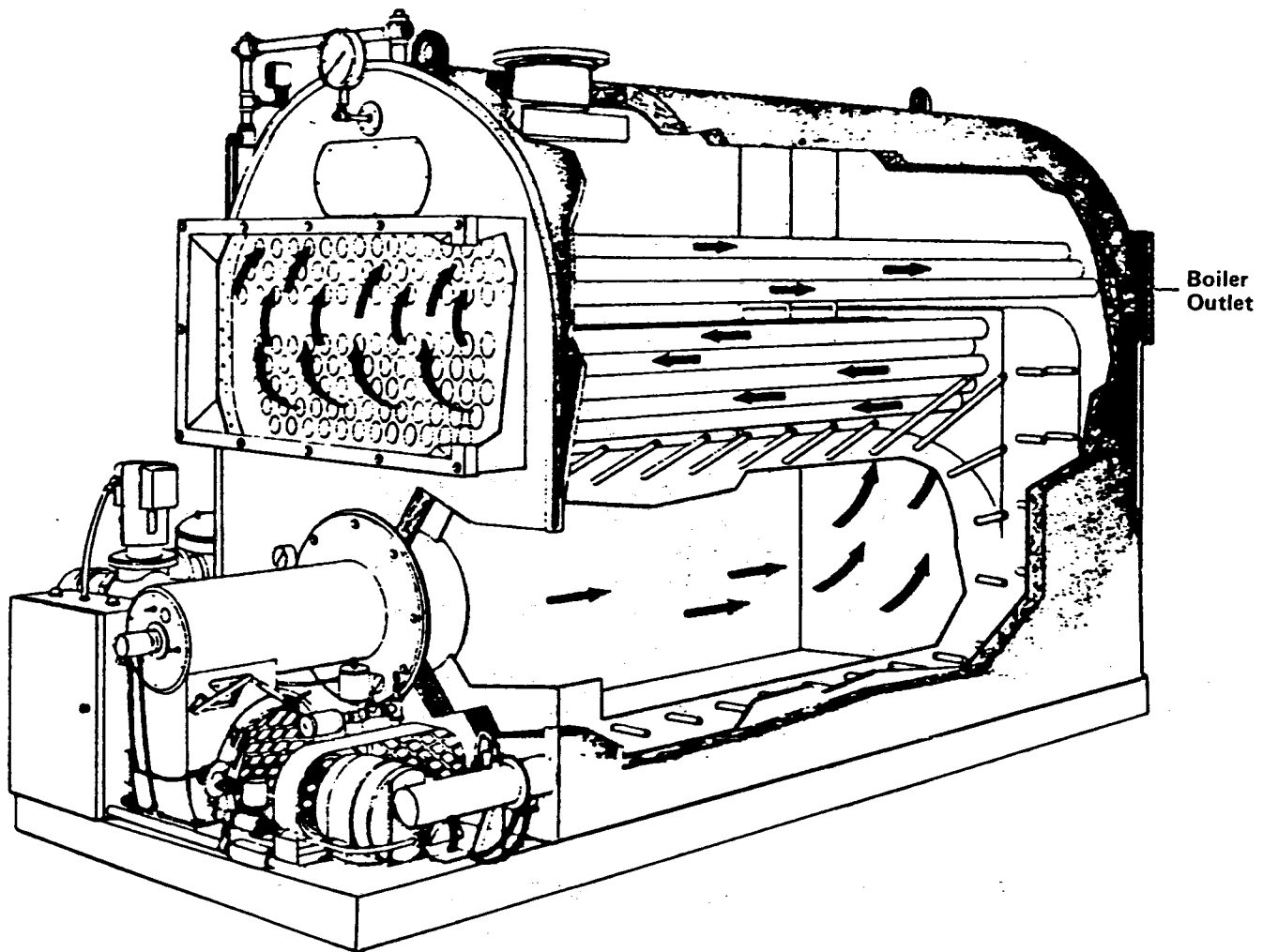


FIGURE 2-5. HORIZONTAL RETURN TUBULAR BOILER

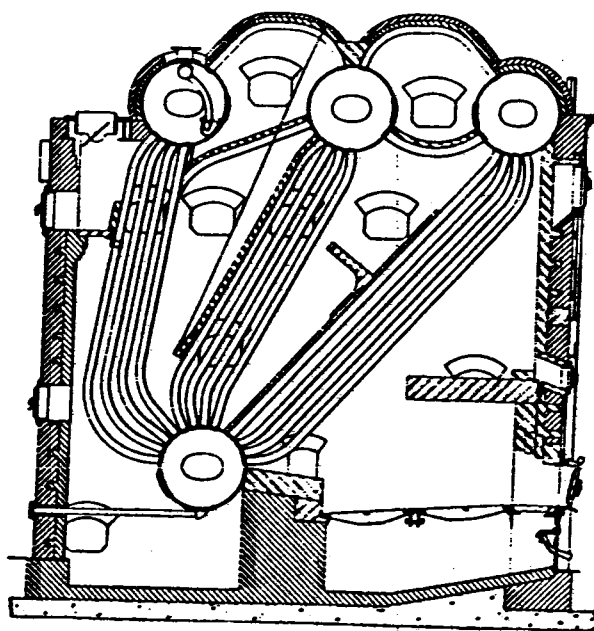


FIGURE 2-6. FOUR DRUM WATER TUBE BOILER

tubes for good heat transfer. Two drum boilers have generally replaced three and four drum units in modern construction, because they are less expensive to construct.

a. Refractory Furnaces. Early boiler designs utilized refractory furnaces as combustion zones. Some furnaces used arches and bridge walls to reflect heat and maintain high temperatures in specific zones for burning anthracite and other hard coals. Since prolonged exposure to high temperature damages refractory material, it is necessary to maintain the heat liberation rate (Btu per hour per cubic foot of furnace volume) of refractory furnaces within reasonable limits. These limits depend upon the type of refractory used, type of fuel, firing method, type of heating surface exposed to the radiant heat, and type of cooling mechanism used. Maximum heat liberation rates for refractory furnaces are in the ranges of 25,000 to 35,000 Btu per hour per cubic foot at full load. In refractory wall construction it is important to allow for the thermal expansion which occurs as the refractory is heated to operating temperatures. Figure 2-7 illustrates typical expansion joint arrangements. The development of high alumina super-duty firebrick, insulating firebrick, block insulation, castable refractory, and plastic refractory have greatly improved refractory life and reduced radiation losses from boiler furnaces. The NAVFAC "Central Heating Plant" Manual MO-205 discusses refractories in greater detail.

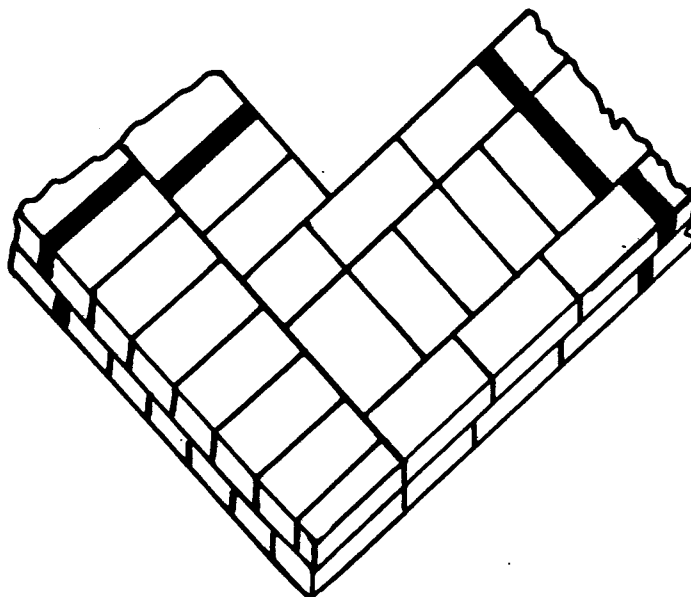
b. Water Wall Construction. Water walls were developed to allow the use of higher firing rates and higher furnace heat release rates, while reducing heat losses and maintenance. Improvements to water wall furnaces and associated casings and lagging also reduce air infiltration into the boiler, reducing excess air levels and improving boiler efficiency. The four types of water wall construction are: tube and tile, tangent tube, studded tube, and membrane wall (reference figure 2-8). The tube and tile construction which was first developed provided only a partial solution to the maintenance and heat loss problems. Minimum practical tube spacing is limited by ability to economically roll the tubes into drums or headers. This, in turn, limits the amount of heat transfer surface added and the amount of protection given to the refractory, and thus limits the practicality of tangent tube construction. Studded tube construction was then developed and was highly effective. In areas with high heat releases such as bridge walls and arches, studded tubes covered with refractory are especially effective. Flue gas can still leak through studded tube wall construction under some circumstances, resulting in corrosion of boiler tubes, and lagging. To obtain completely gas-tight construction and maximize heat transfer, membrane water wall construction was developed and remains the best, though most expensive, water wall design.

c. Steam Drum Internals. Steam drums are equipped with mechanical separators to ensure that the steam leaving the boiler does not contain solids or other impurities and that steam-free water is made available to continue the natural circulation process in the boiler. A dry pipe, the earliest device used, was placed inside the shell or drum just below the steam outlet nozzle. Numerous small holes drilled in the upper half of the dry pipe cause separation of the steam from the water. The trend in boiler design toward ever higher heat transfer rates makes separation of water and steam more difficult and limits the application of the dry pipe. Combinations of baffles, cyclone-type separators, corrugated scrubbers, and perforated plates are now used to effectively separate water and steam. Figure 2-9 illustrates modern steam drum internals. The cyclones are arranged in a row and receive the water/steam mixture tangentially from the boiler water wall and generating tubes. The water is spun to the outside of the cyclone and exits through the open bottom of the cyclone. The steam is less dense and thus stays in the center and exits through the open top of the cyclone. Scrubbers further reduce the amount of water entrained. Solids in condensed steam from a well-designed steam drum should be less than 3 ppm.

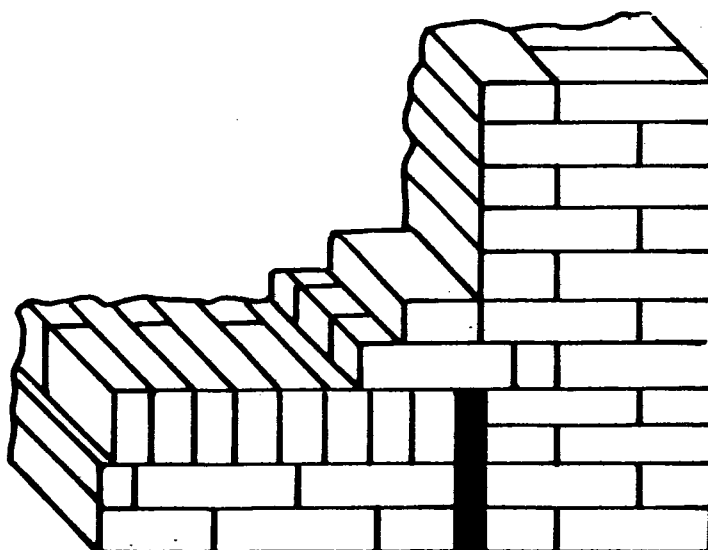
d. Generating Surface. Boiler tubes that connect the upper and lower drums are called generating surfaces and are included with the water wall surface in computing the total heating surface. Many different tube spacings are used, depending on the type of fuel being fired. The tubes may be inline or staggered. A staggered tube arrangement would not be acceptable for coal- or heavy oil-fired boilers due to its susceptibility to ash buildup; however, it provides better heat transfer for gas- or light oil-fired units.

e. Superheaters. Some processes and turbines require steam that is super-heated above the saturated steam temperatures. Figure 2-10 illustrates a two-drum boiler equipped with a superheater, water walls, spreader stoker, and economizer. The steam from the steam drum is directed to a superheater inlet header and then through the superheater tubes to the outlet header and steam outlet. A superheater can be arranged in many ways and may be located behind a row of generating tubes. These tubes cool the furnace gases somewhat before reaching the superheater tubes and shield the superheater tubes from radiant heat. Superheaters are not commonly found in Army Central Boiler Plants.

f. Package Boilers. Packaged water tube boilers are factory-assembled, complete with combustion equipment, mechanical draft equipment, automatic controls, and accessories. These factory-assembled packages can be purchased in capacities exceeding 200,000 lb/hr. Package boilers are available in three basic configurations: "D", "A", and "O" (Figure 2-11). Figure 2-12 illustrates a "D" type package boiler arranged for oil and gas firing. Note

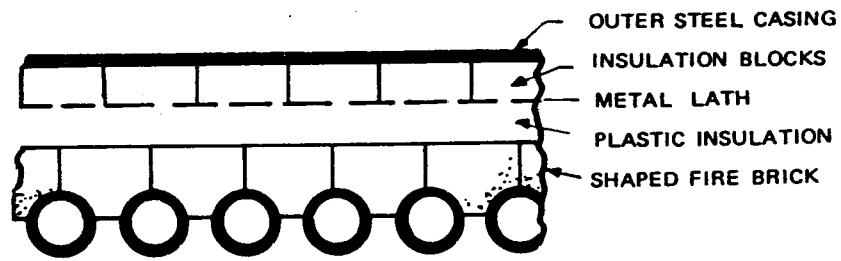


Corner Construction With
Staggered Expansion Joints
(18" Wall)

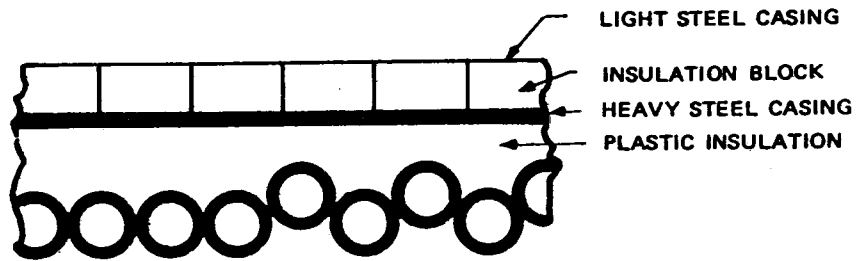


Floor to Wall Expansion Joint

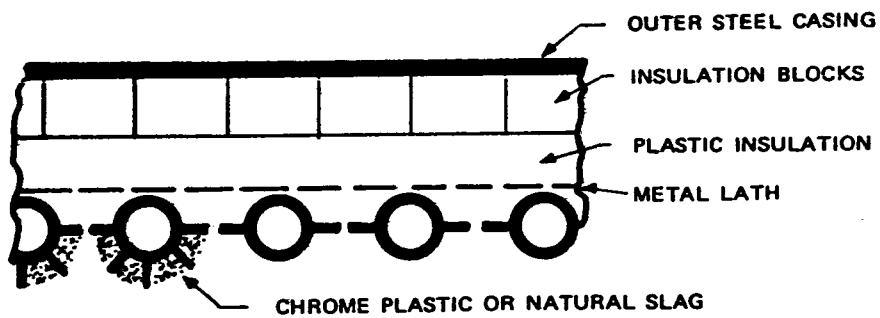
FIGURE 2-7. REFRACTORY EXPANSION JOINTS



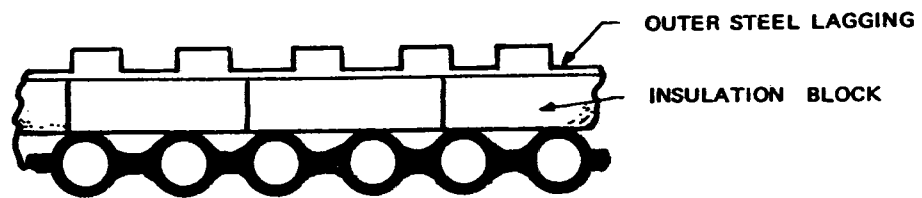
TUBE AND TILE



TANGENT TUBE



STUDED TUBE



MEMBRANE WALL

FIGURE 2-8. WATER WALL CONSTRUCTION

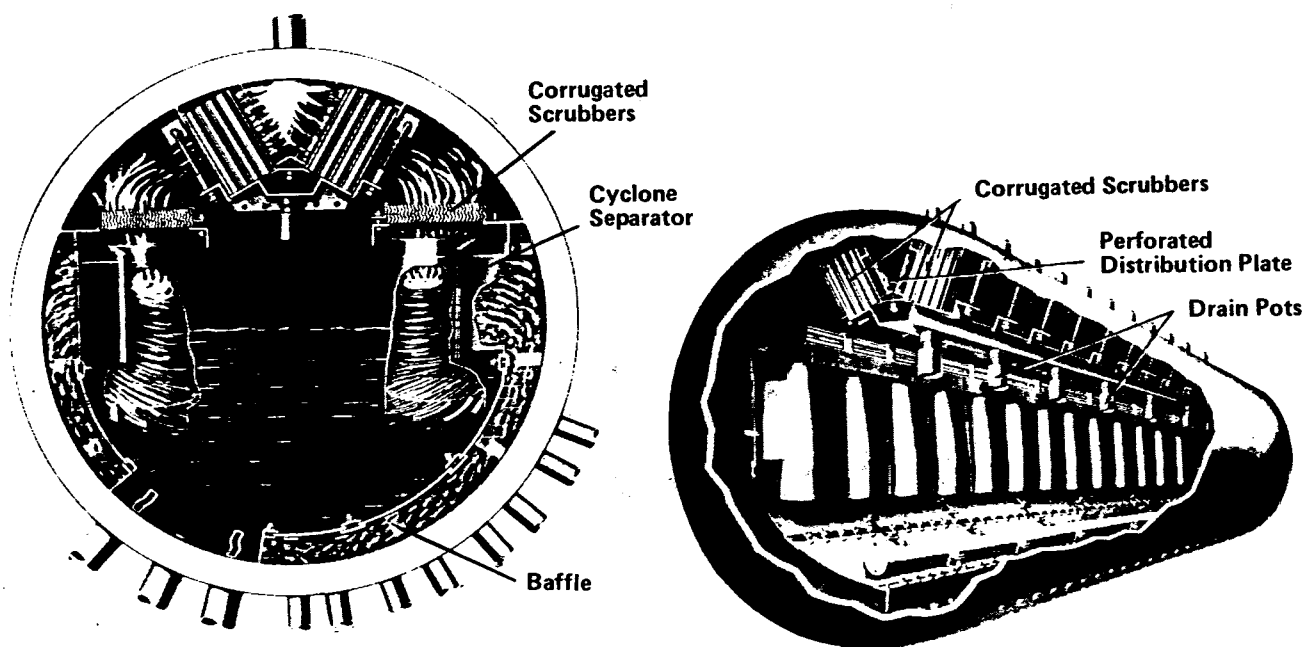


FIGURE 2-9. STEAM DRUM INTERNALS

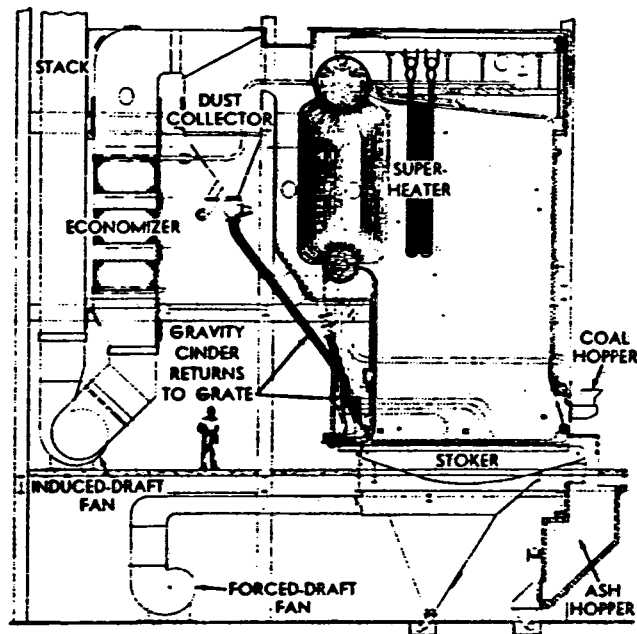


FIGURE 2-10. SUPERHEATER IN TWO DRUM BOILER

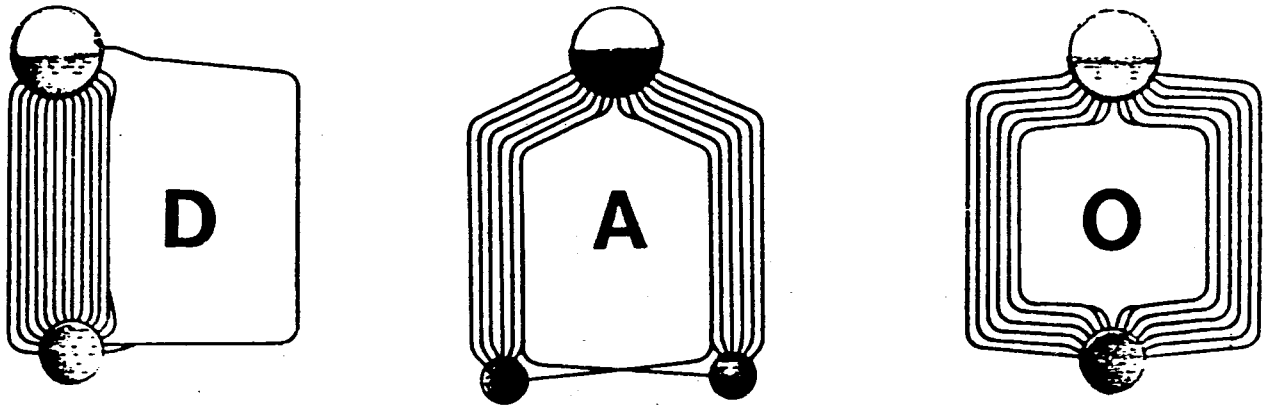


FIGURE 2-11. PACKAGE BOILER CONFIGURATIONS

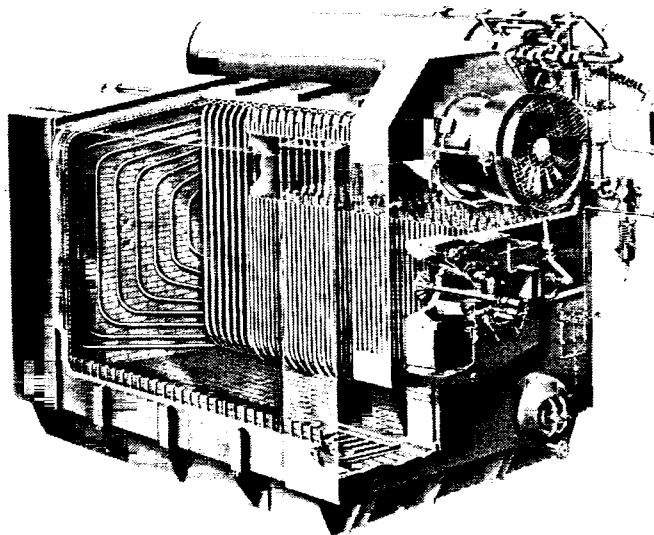


FIGURE 2-12. "D" PACKAGE BOILER

that the flame travels lengthwise down the furnace where combustion is completed. The flue gases then make a 180° turn and come back to the burner end of the boiler, exiting from the side of the generating bank tubes. Historically, package boilers have been designed to fire only natural gas and oil. Coal firing has not been practical due to the high ash content of the coal which would plug the boiler generating banks. Package boilers have been widely and successfully applied for Central Boiler Plant service.

2.6. HOT WATER GENERATORS.

Hot water generators are often called hot water boilers, even though little or no boiling occurs. Modified Scotch boilers and a variety of package boilers are available. These boilers have limited and uneven water circulation characteristics if natural circulation is utilized because of the small natural circulation forces available. Special boilers have thus been developed that use forced circulation to improve heat transfer rates. Figure 2-13 illustrates this type of hot water generator. Note that the steam and mud drums have been replaced with headers. The hot water generator is connected to a hot water distribution system. As water is heated in the hot water generator, the water expands. When the hot water is distributed to various heat exchangers, as illustrated in figure 2-14, the water cools and contracts. An expansion drum, pressurized by either steam or inert gas, is provided to adjust for these volume changes. One or more centrifugal pumps are required to circulate water through the system. Figure 2-15 illustrates a high temperature water system equipped with a steam-pressurized expansion drum, a circulating pump for the generator, and a circulating pump for the distribution system. Many other arrangements are possible. A more detailed discussion of hot water generators and distribution systems is provided in Army Manual TM 5-810-2, entitled "High Temperature Water Heating Systems."

2.7. ECONOMIZERS.

Economizers are used to recover heat from the boiler flue gases and thereby increase boiler efficiency. The heat absorbed by the economizer is transferred to the boiler feedwater flowing through the inside of the economizer tubes. Because feedwater temperatures are much lower than saturated steam temperature, an effective temperature differential exists, enabling good heat transfer and low economizer exit gas temperatures. Continuous tube construction is common. Bare tubes are used for coal-fired boilers, while fin-tubes or extended surfaces are commonly used on gas- and oil-fired units. Figure 2-16 shows a continuous bare tube economizer. Figure 2-17 illustrates a steel-finned extended surface economizer. The extended surface promotes heat transfer from the gas by

providing more heating surface. Care must be taken when selecting the number of fins per inch. Extended surface economizers on natural gas-fired boilers may use up to nine fins per inch, while only two fins per inch would be used for heavy oil-fired applications. Provision for cleaning with sootblowers is necessary for economizers on coal- or oil-fired boilers. Economizers are usually arranged with gas flow down and water flow up. This maximizes heat transfer and helps to avoid water hammer. Economizers are usually designed with water temperatures below the saturated temperature of the water to avoid producing steam. Economizers should be equipped with three-valve bypass on the water side to allow servicing or bypassing water at low boiler loads. This helps to minimize economizer corrosion when high sulfur fuels are burned. Figure 2-18 provides curves which establish minimum metal temperatures allowable for corrosion protection in economizers and air heaters. Since the water temperature in the economizer is normally above 212° F, the fuel sulfur content would have to be less than 2% for stoker-fired coal or 2.6% for oil-fired boilers to minimize corrosion problems during operation. Methods for avoiding corrosion during idle or standby periods are discussed in paragraph 3-27. Economizers are pressure parts and, as such, must be manufactured and stamped in accordance with the ASME Boiler and Pressure Vessel Code. Economizers equipped with three-valve bypasses must be equipped with one or more safety valves.

2-8. AIR HEATERS.

Air heaters, like economizers, are used to recover heat from boiler flue gases and thereby increase the boiler efficiency. The heat absorbed by the air heater is transferred to the combustion air before the air enters the burners and boiler. This preheated air not only improves efficiency by recovering otherwise lost heat, but also can improve the combustion of some fuels by promoting higher furnace temperatures. There are two general types of air heaters. Recuperative air heaters, like the tubular air heater illustrated in figure 2-19, transfer heat from the hot flue gases on one side of the tube to the combustion air on the other side of the tube. Regenerative air heaters, like the rotary heat wheel illustrated in figure 2-20, transfer heat indirectly by heating a plate with the hot gas and then rotating that hot plate into the cool combustion air which then absorbs the heat. Rotary heat wheels are equipped with seals that separate the flue gas side from the combustion air side of the wheel. Air infiltration from the air side to the gas side is minimized but not eliminated, and is a factor which must be considered when sizing forced and induced draft fans. Provisions for sootblowers are required if dirty or high-ash fuels are being fired. Cold

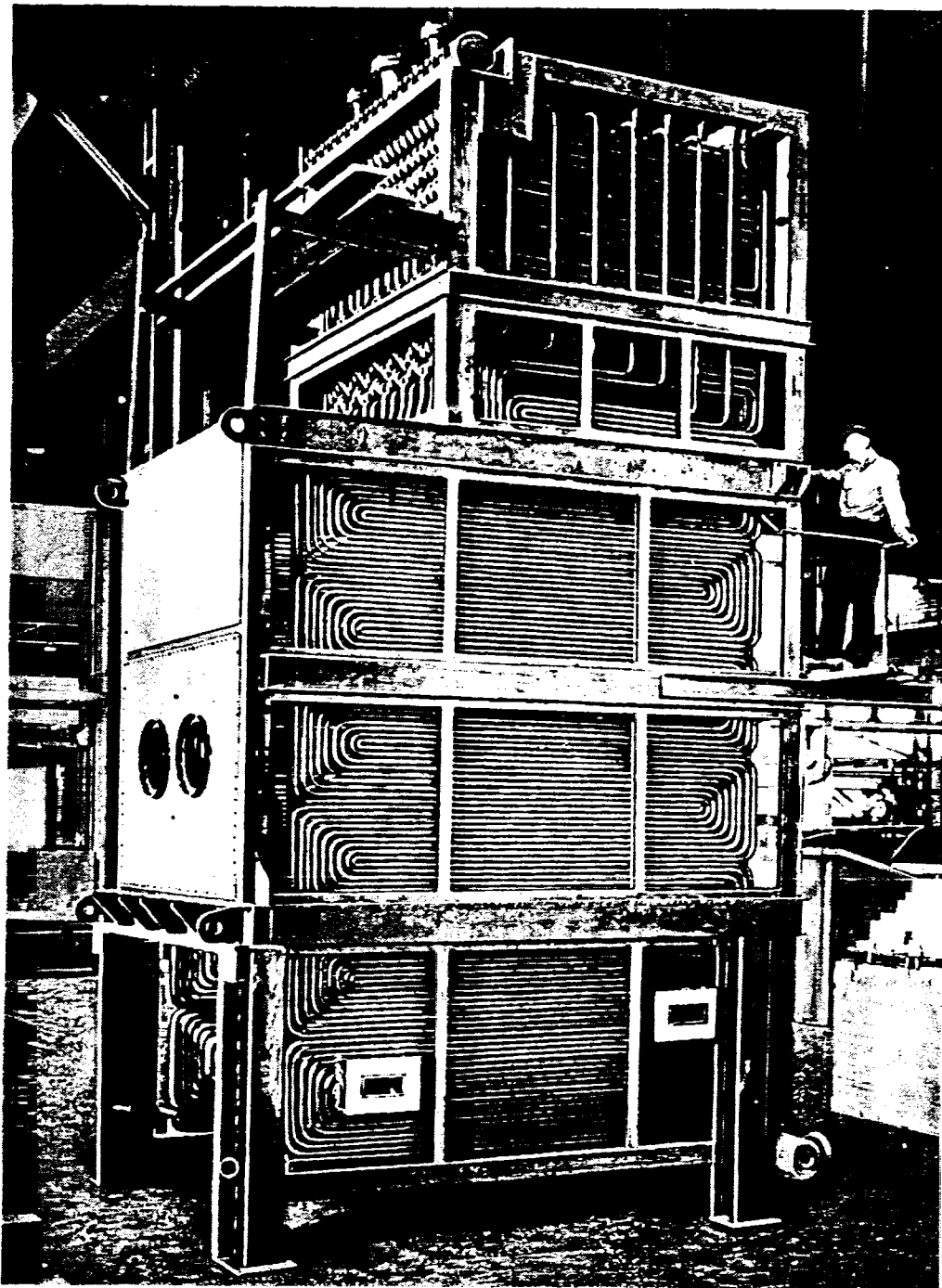


FIGURE 2-13. HOT WATER GENERATOR

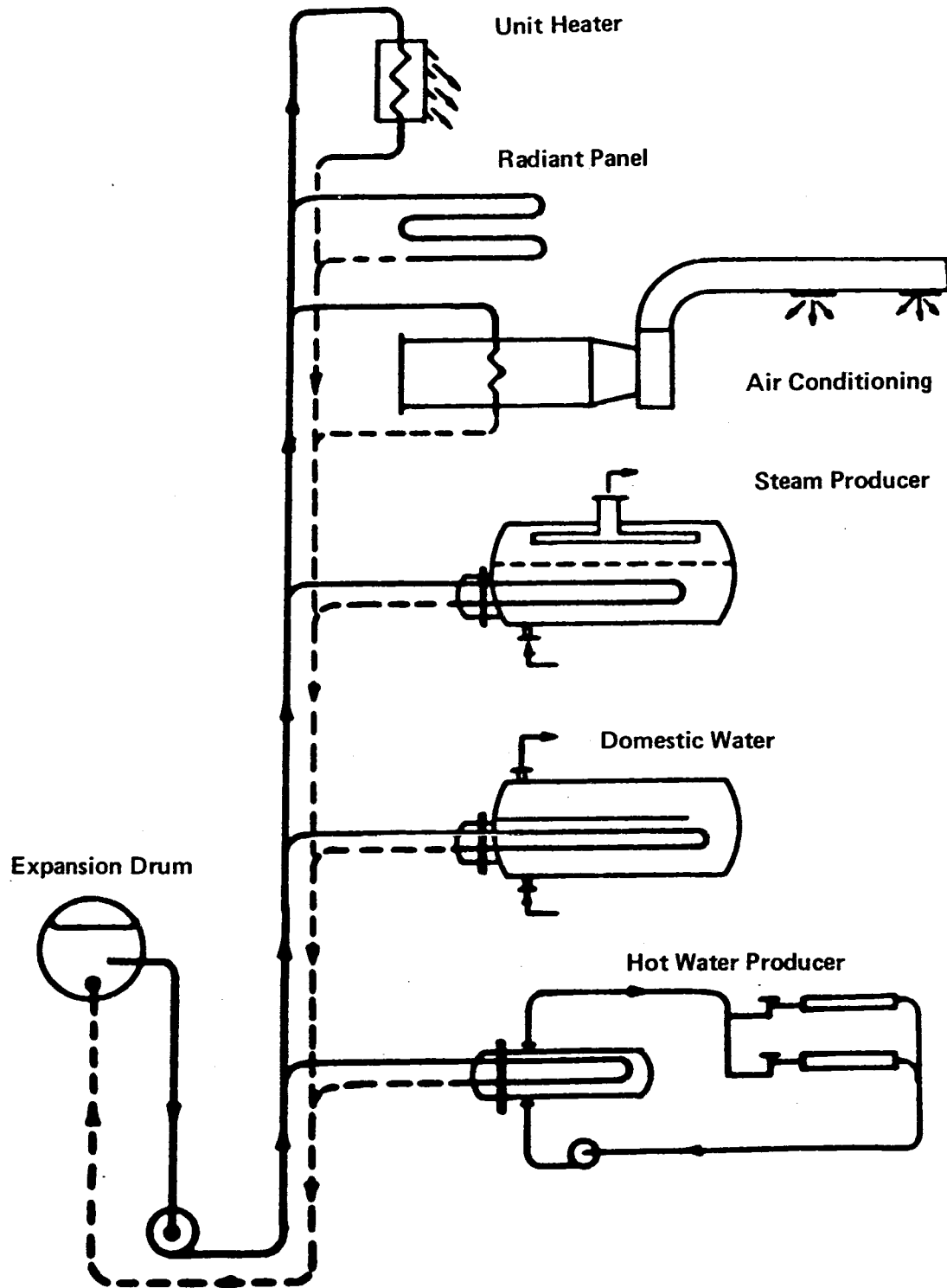


FIGURE 2-14. HOT WATER END USES

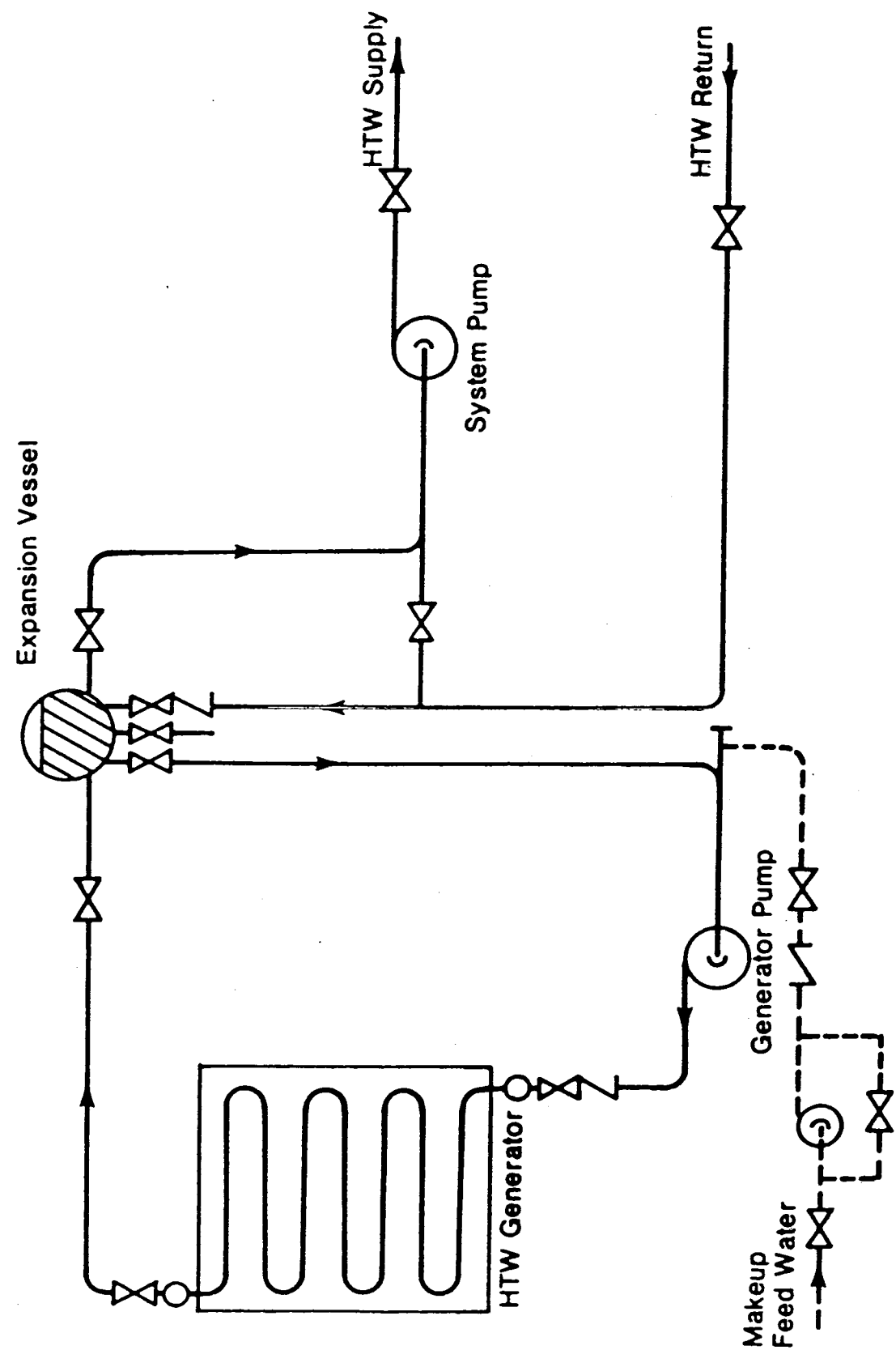


FIGURE 2-15. HOT WATER DISTRIBUTION

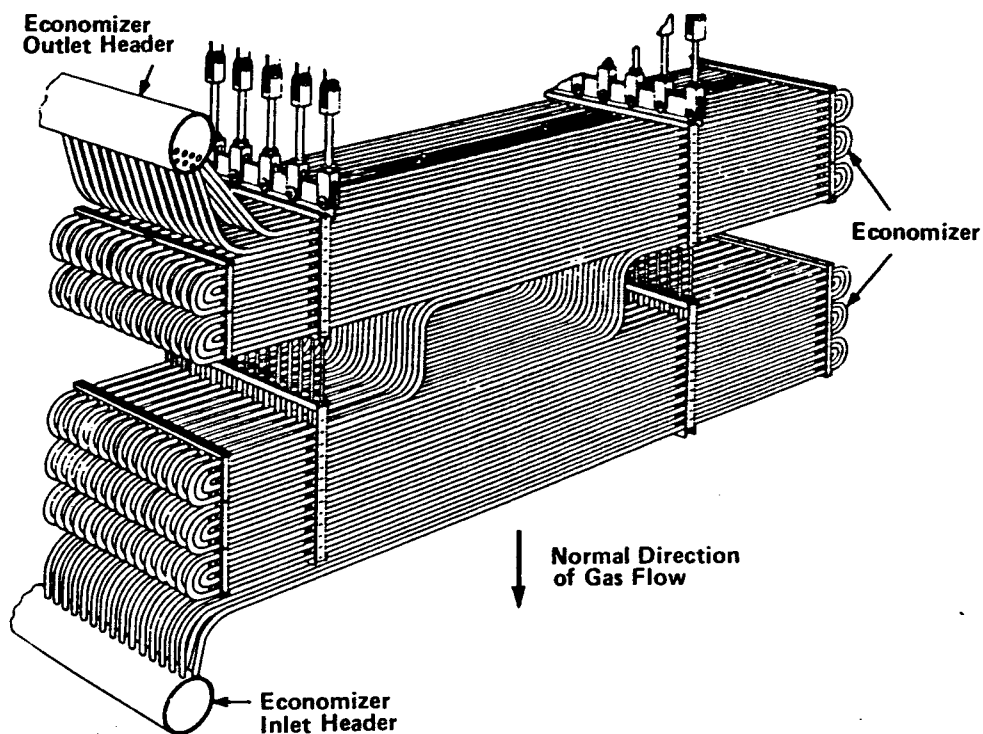


FIGURE 2-16. BARE TUBE ECONOMIZER

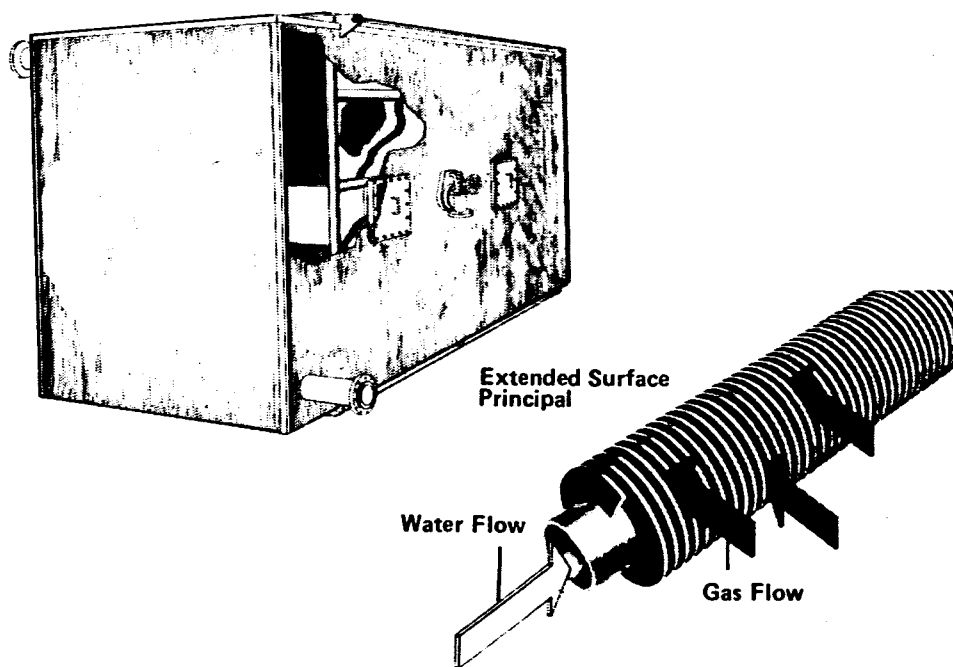


FIGURE 2-17. EXTENDED SURFACE ECONOMIZER

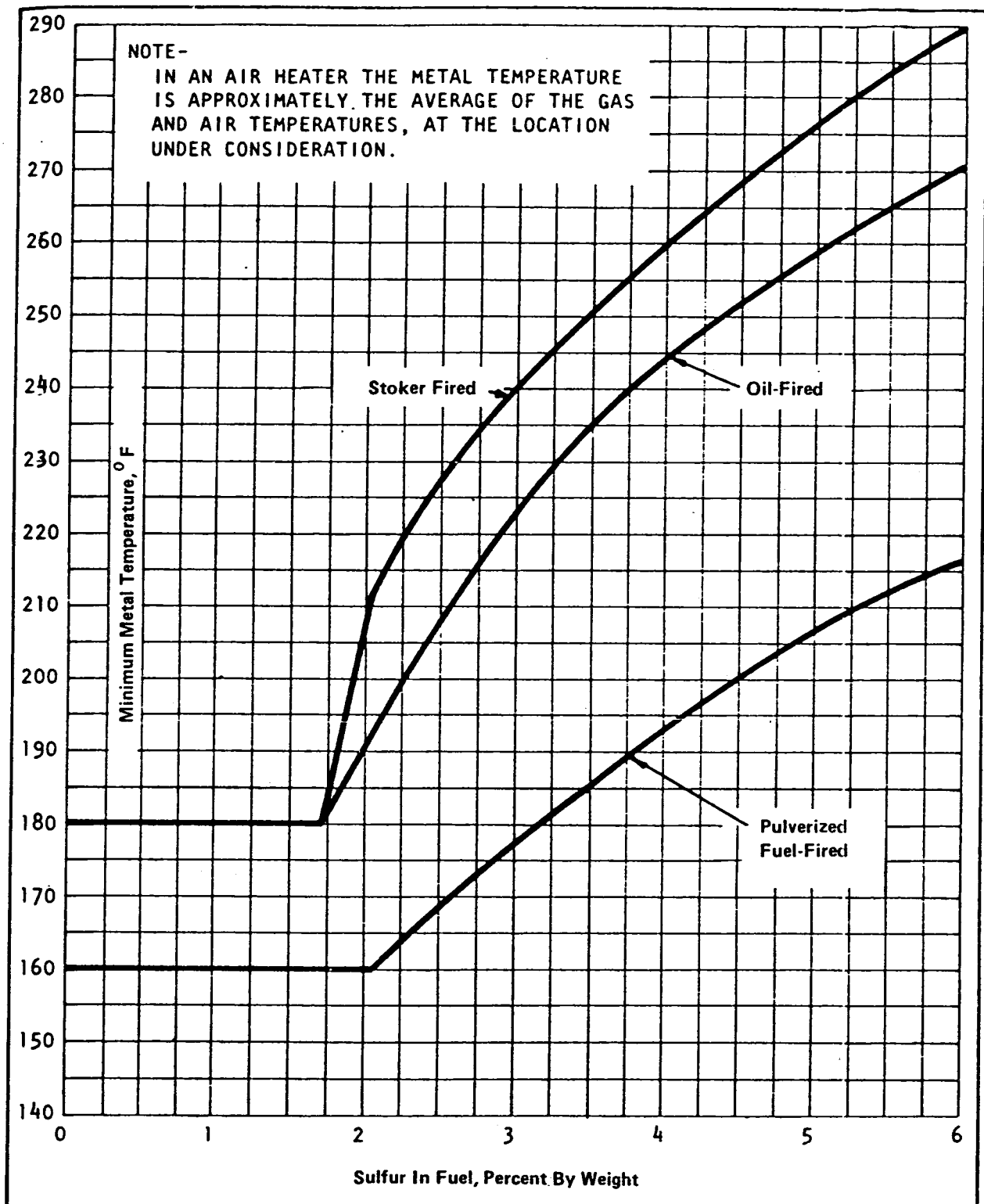


FIGURE 2-18. COLD END CORROSION -
MINIMUM METAL TEMPERATURES

end corrosion is more of a problem in an air heater than an economizer because of the low entering combustion air temperatures. Figure 2-18 establishes minimum allowable metal temperature if corrosion is to be controlled. Cold air bypass ducts and dampers, hot air recirculation,

steam coil air heaters, and low-level economizers are examples of methods for preheating the combustion air before it enters the air heater. These methods help control cold end corrosion but also reduce the efficiency of the system by raising exit gas temperatures.

SECTION II. BOILER ACCESSORIES AND FITTINGS

2-9. ASME REQUIREMENTS.

To ensure safe operation, the ASME Boiler and Pressure Vessel Code requires that boilers be equipped with a water gage glass and gage cocks, water column, pressure gage, and safety valves. Forced circulation, high temperature water boilers which have no water line do not require a gage glass and gage cocks, but a temperature gage is required. Detailed requirements for the location and installation of these accessories on power boilers are found in Section I of the ASME Boiler and Pressure Vessel Code, and the requirements for heating boilers are in Section IV. Section IV requires each boiler to be equipped with two controls to cut off the fuel supply so as to prevent steam pressure or water temperature from exceeding boiler limits. These controls are pressure operated for steam boilers and temperature operated for hot-water boilers. Low-water fuel cutoff instrumentation is also required. Oil and gas-fired boilers must be equipped with suitable flame safeguard controls, safety limit controls, and burners which are approved by a nationally recognized organization.

2-10. GAGE GLASS, GAGE COCKS.

Each boiler must have at least one water gage glass. If the operating pressure is 400 psig or greater, two gage glasses are required on the same horizontal line. Each gage glass must have a valved drain, and the gage glass and pipe connections must not be less than ½ inch pipe size. The lowest visible part of the gage glass must be at least 2 inches above the lowest permissible water level, which is defined as the lowest level at which there is no danger of overheating any part of the boiler during operation. For horizontal fire tube boilers the gage glass is set to allow at least 3 inches of water over the highest point of the tubes, flues, or crown sheet at its lowest reading. Figure 2-21 illustrates a typical water gage. Each gage consists of a strong glass tube connected to the boiler or water column by two special fittings. These fittings sometimes have an automatic shutoff device that functions if the water glass falls. Requirements for the fabrication of these shutoff devices are also given in the ASME Code. When the boiler operating pressure exceeds 100 psig, the

gage glass must be furnished with a connection to install a valved drain to some safe discharge point. Each boiler must have three or more gage or try cocks located within the visible length of the gage glass. Gage cocks are used to check the accuracy of the boiler water level as indicated by the gage glass. They are opened by handwheel, chain wheel, or lever, and are closed by hand, a weight, or a spring. The middle cock is usually at the normal water level of the boiler; the other two are spaced equally above and below it. Spacing depends on the size of the boiler.

2-11. WATER COLUMNS

A water column is a hollow cast-iron, malleable-iron, or steel vessel having two connections to the boiler. The top connection enters the steam space of the boiler through the top of the shell or head, and the water connection enters the shell or head at least 6 inches below the lowest permissible water level. The pipe used to connect the water column to the boiler may be brass, iron, or steel, depending on the pressure; it must be at least 1 inch in diameter. Valves or cocks are used in these connecting lines if their construction prevents stoppage by sediment deposits and if the position of the operating mechanism indicates whether they are open or closed. Outside screw-and-yoke-type gate valves are generally used for this service. Lever-lifting-type gate valve or stop cocks with permanently attached levers arranged to indicate open or closed position may also be used. **These valves or cocks must be locked open.** Crosses are generally used in place of elbows or tees on the piping between the water column and the boiler to facilitate cleaning the line. A valved drain or blowdown line is connected to the water column for removal of mud and sediment from the lines and column. Ends of all blowdowns should be open and located for ease of inspection. The water column shown in figure 2-22 is equipped with high- and low-water alarms which operate a whistle to warn the operator. The whistle is operated by either of the two floats.

2-12. PRESSURE GAGE, TEMPERATURE GAGE.

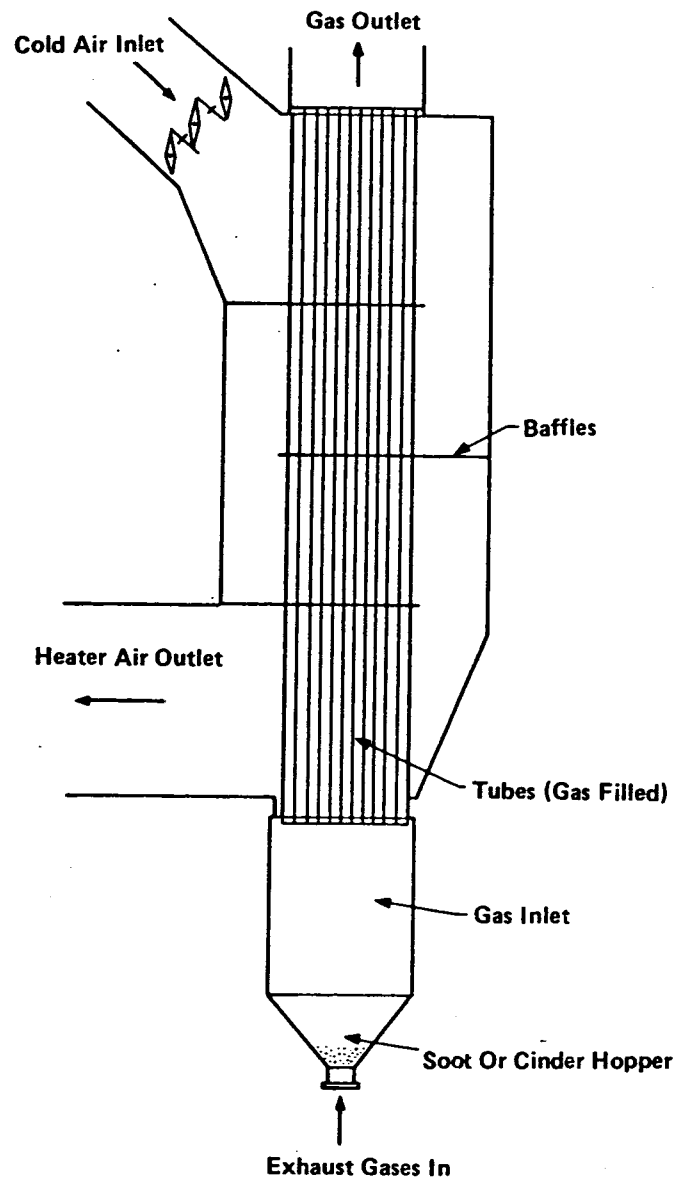


FIGURE 2-19. TUBULAR AIR HEATER

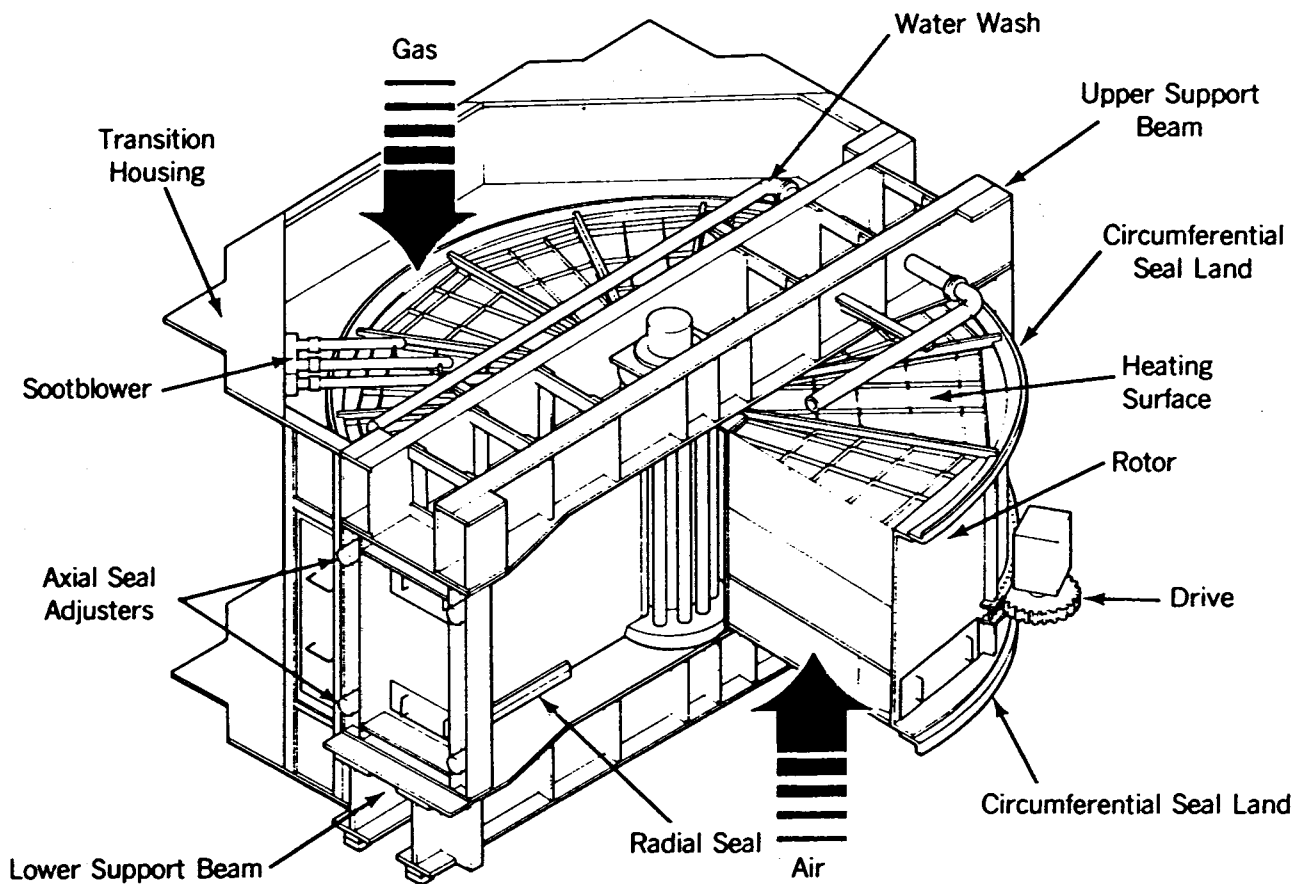


FIGURE 2-20. REGENERATIVE AIR HEATER

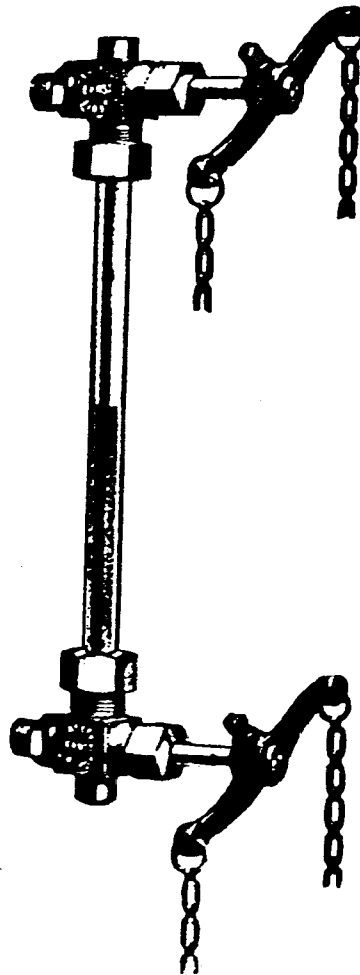


FIGURE 2-21. WATER GAGE GLASS

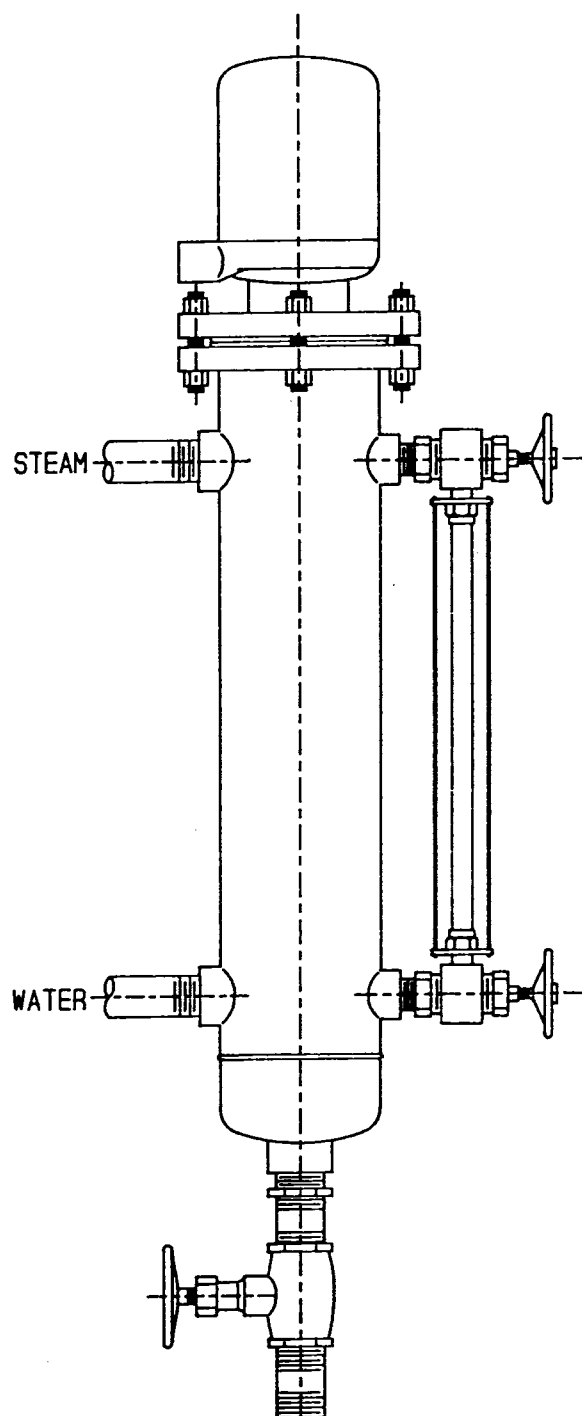


FIGURE 2-22. WATER COLUMN

Every boiler must be equipped with an easily readable pressure gage. The pressure gage must be installed so that it indicates the pressure in the boiler at all times. Each steam boiler must have the pressure gage connected to the steam space or to the steam connection of water column. A valve or cock must be placed in the gage connection adjacent to the gage. An additional valve or cock may be located near the boiler, provided that it is locked or sealed in the open position. No other shutoff valves may be located between the gage and the boiler. The pipe connection must be of ample size and arranged so that it may be cleared by blowing out. For a steam boiler the gage or connection must contain a syphon or equivalent device which will develop and maintain a water seal to prevent steam from entering the gage tube. Pressure gage connections must be suitable for the maximum allowable working pressure and temperature. The connections to the boiler must not be less than $\frac{1}{4}$ inch standard pipe size. Where steel or wrought iron pipe or tubing is used, it must be at least $\frac{1}{2}$ inch inside diameter. The dial of the pressure gage must be graduated to approximately double the pressure at which the safety valve is set, and it should never be less than $1\frac{1}{2}$ times this pressure. Every hot water boiler must also have a temperature gage located and connected for easy readability. The temperature gage must be installed so that it indicates the boiler water temperature at or near the outlet connection at all times.

2-13. SAFETY VALVES.

Safety valves are installed to prevent excessive pressure buildup in the boiler, superheater, or economizer. Safety valves are designed to quickly pop to the full open position when the steam pressure rises to the set point and to quickly close when the pressure drops a preset amount (blowdown or blowback). They must close tightly without chattering or leakage, and remain tightly closed after reseating. Their construction, installation, and performance are rigidly prescribed in the ASME Code. No valve or stop is permitted between the boiler and safety valve, and the discharge line must be supported separately to prevent any undue stress on the valve. A recommended method of installation is shown in figure 2-23. Any economizer which may be shut off from the boiler must have one or more safety valves. Every superheater must also have one or more safety valves located near the superheater outlet. A safety valve is defined as an "automatic pressure-relief device actuated by a static pressure upstream of the valve and characterized by full opening pop action." A safety valve is used for gas or vapor service, including steam. Hot water boilers use a safety relief valve which is defined as an "automatic pressure-actuated relief device suitable for use either as a safety valve or relief valve, depending on the application."

All safety valves and safety relief valves are constructed so that the failure of any part cannot obstruct the free and full discharge of steam or water from the valve. Safety relief valves, like safety valves, must be manufactured and stamped in accordance with the ASME Code. Figure 2-23. Safety Valve Installation

a. Types of Safety Valves. One common type of safety valve is the huddling chamber safety valve illustrated in figure 2-24. This safety valve opens rapidly because of the additional area on which steam pressure is exerted as soon as the valve starts to lift from the seat, and the reaction of the steam on the seat. This second action resembles the action which causes a free air, water, or steam hose to whip around when the discharge velocity is high. The area between the valve seat and the adjusting ring is called the huddling chamber. As seen in figure 2-24, the clearance between the inside of the adjusting ring and the feather is comparatively small. The boiler pressure is exerted on the area of the feather which is equal to the inside area of the seat bushing. As soon as the seat is slightly displaced, steam starts to flow through the valve because of the excessive boiler pressure. The steam cannot escape between the feather and the adjusting ring as fast as it is flowing through the seat. As a result, pressure builds up under the feather. This in turn, increases the force available for pushing the valve off the seat. The flow of steam is turned by the feather, and this also exerts a force to open the valve. These two forces cause the valve to pop open. Because of the larger area subjected to the steam pressure and the reactive force of the flowing steam, the valve does not close until the pressure drops below that which caused it to open. The difference between the set or popping pressure and the closing pressure is called the blowdown. Jet flow and nozzle reaction safety valves are other common types. Power-actuated pressure relief valves are also allowed by ASME Code but are not used in Army installations.

b. Safety Valve Capacity. The safety valve capacity for each boiler must be such that the valve or valves will discharge all the steam that can be generated by the boiler without allowing the pressure to rise more than 6% above the highest pressure at which any valve is set, and in no case to more than 6% above the maximum allowable working pressure. The safety valve capacity must be in compliance with ASME Code and must not be less than the maximum designed steaming capacity as determined by the manufacturer. The required steam relief capacity, (in lb/hr) of the safety relief valves on a high-temperature water boiler is determined by dividing the maximum output in Btu/hr at the boiler nozzle by 1000. Economizer safety valve capacity is calculated from the maximum heat absorption in Btu/hr divided by 1000.

c. Safety Valve Settings. One or more safety valves on

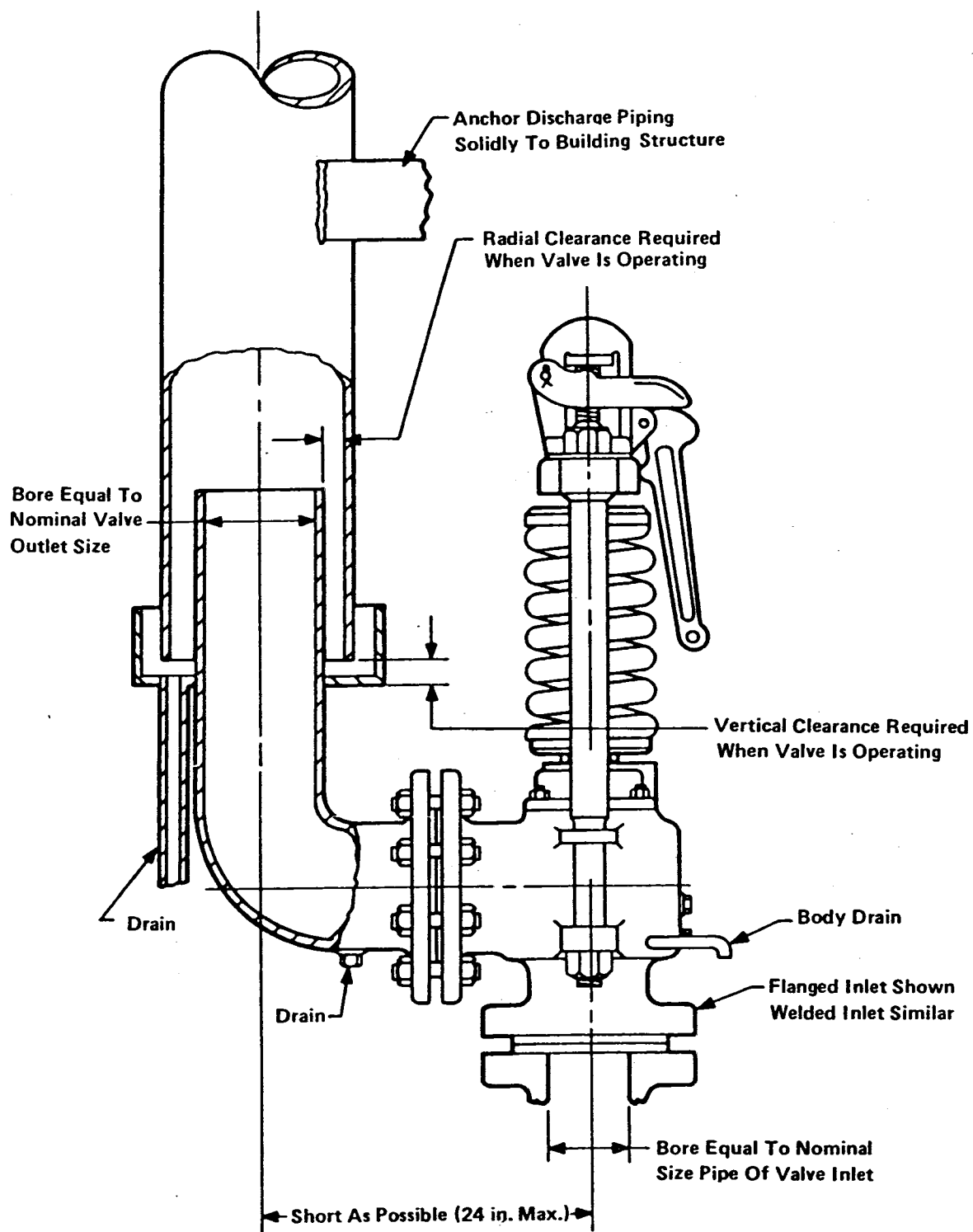


FIGURE 2-23. SAFETY VALVE INSTALLATION

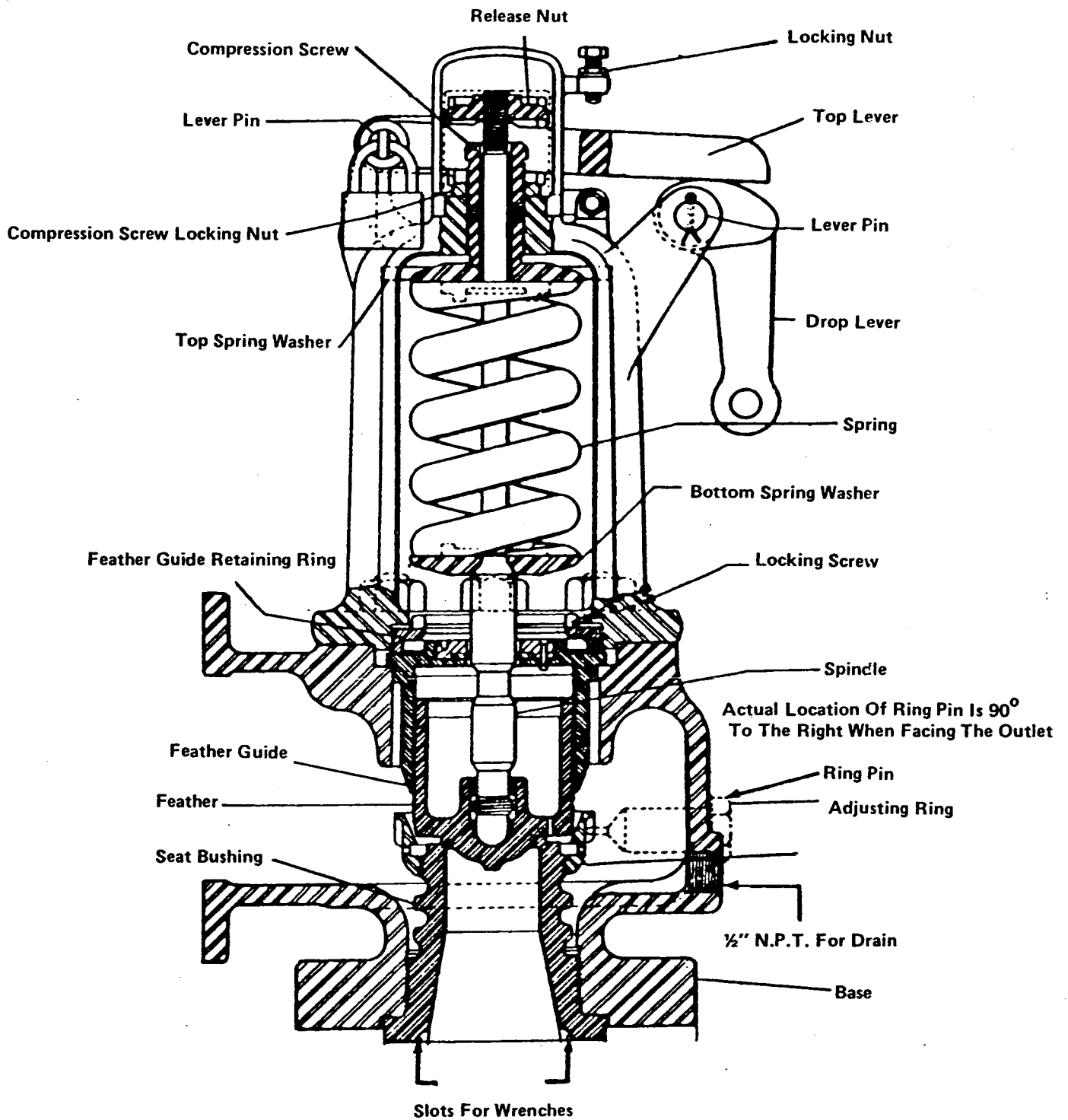


FIGURE 2-24. HUDDLING CHAMBER SAFETY VALVE

the boiler proper must be set at or below the maximum allowable working pressure. If additional valves are used, the highest pressure setting must not exceed the maximum allowable working pressure by more than 3%. The complete range of pressure settings of all the saturated-steam safety valves on a boiler must not exceed 10% of the highest pressure to which any valve is set. Pressure setting of safety relief valves on high-temperature water boilers may exceed this 10% range because safety relief valves in hot water service are more susceptible to damage and subsequent leakage than safety valves relieving steam. It is recommended that the maximum allowable working pressure of the boiler and the safety relief valve setting for high-temperature water boilers be selected substantially higher than the desired operating pressure to minimize the frequency of safety relief valve lift.

2-14. BOILER OUTLET VALVES.

Each steam discharge outlet from a boiler, except the safety valve and superheater connections, must have a stop valve. If the valve is over 2 inch pipe size, it must be the outside screw-and-yoke rising-spindle type; the spindle position indicates whether the valve is open or closed. Reference figure 2-25. A plug-type cock may be used if the plug is held in place by a gland or guard, if it allows remote indication of opening or closing, and if it is used with a show-opening mechanism. When two or more boilers are connected to a common header, the steam connection from each boiler having a manhole opening must be fitted with two stop valves with an ample, free blow drain between them. The stop valves should consist, preferably, of one nonreturn valve set next to the boiler and a second valve of the outside screw-and-yoke type. However, two outside screw-and-yoke-type valves may be used. The nonreturn valve is a type of check valve which can be held closed (reference figure 2-26). It can be opened only by pressure in the boiler, and it closes when the boiler pressure is lower than the header pressure, a condition which may be caused by burst tube, loss of fire, or other reasons. The valves require a very small difference in pressure for proper operation. A dashpot is provided to prevent chattering or too rapid movement of the valve. Ladders and catwalks or other means for operating the valves from the operating floors in boiler rooms should be provided.

2-15. BLOWOFF VALVES AND PIPING.

Each boiler must have at least one blowoff connection installed at the lowest water space available to allow removal of sludge. The pipe used must not be less than 1 inch or over 2½ inches. Extra-strong pipe must be used for pressures above 100 psig. The blowoff line must be protected from direct furnace heat by brickwork or other

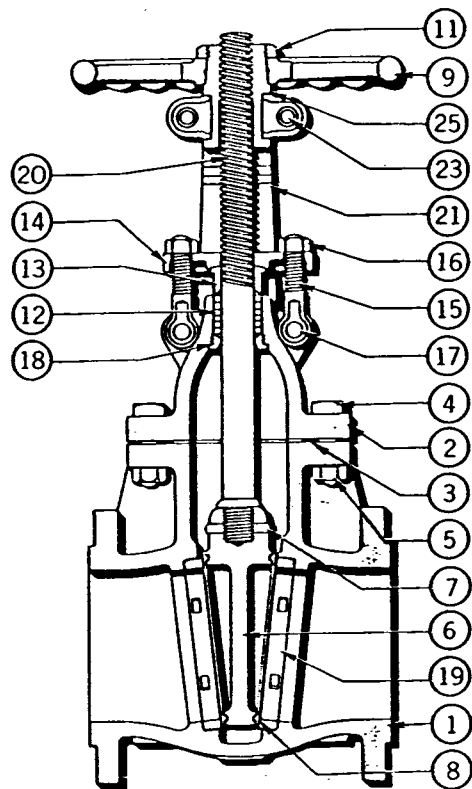
heat-resisting material which is constructed to allow for inspection of the pipe. This is necessary because sediment collects in the blowoff line and, since there is no circulation of the water, the pipe may easily become overheated and burn out. Care must be taken to ensure ample room for expansion and contraction at the junction of the pipe and the setting. One slow-opening valve may be used in the blowoff line for pressures up to 100 psig. Two slow-opening valves, or a slow-opening valve and cock, are required for pressures above 100 psig. A typical slow-opening valve set is shown in figure 2-27. A slow-opening valve is one which requires at least five complete turns of the operating mechanism to change from the completely open to the completely closed positions and is used to avoid shock to the piping and possible injury to personnel. Valves which have dams or pockets in which sediment can collect must not be used. Boiler blowdown is provided for the control of dissolved and suspended solids which concentrate in steam boilers. This is a separate subject and is discussed in paragraph 4-8.

2-16. FUSIBLE PLUGS.

Fusible plugs are sometimes used on fire tube boilers to provide added protection against low water. They are constructed of bronze or brass with a tapered hole drilled lengthwise through the plug and filled with a low-melting alloy consisting mostly of tin. There are two types of fusible plugs, fire-actuated and steam-actuated.

a. Fire-Actuated Plug. Fire-actuated plugs are filled with an alloy of tin, copper, and lead with a melting point of 445 to 450° F. They are screwed into the shell or a special tube at the lowest possible water level. One side of the plug is in contact with the fire or hot gases, and the other side with water. As long as the plug is covered with water, the tin does not melt. If the water level drops below the plug, the tin melts and is blown out. The boiler then must be taken out of service to replace the plug. Fusible plugs of this type are renewed regularly once a year. The old castings should not be reused, but should be replaced with new plugs obtained from the boiler manufacturer.

b. Steam-Actuated Plug. The steam-actuated plug is installed on the end of a pipe outside the drum. The other end of the pipe, which is open, is at the lowest permissible water level. A valve is usually installed between the plug and the drum. The metal in the plug melts at a temperature below that of the steam in the boiler. The pipe is small enough to prevent water from circulating inside it and cooling the plug. The water around the plug is much cooler than the water in the boiler as long as the end of the pipe is below the water level. However, if the water level drops below the open end of the pipe, the cool water runs out of the pipe and steam condenses on the plug. The steam



NO.	DESCRIPTION
1	BODY
2	BONNET
3	BONNET GASKET
4	BONNET BOLT
5	BONNET BOLT NUT
6	DISC
7	DISC PIN
8	DISC RING—TRIM 6
9	HANDWHEEL
11	HANDWHEEL NUT
12	PACKING
13	PKG. GLAND
14	PKG. GLAND FLG.
15	EYEBOLT
16	EYEBOLT NUT
17	EYEBOLT RIVET
18	REPKG. SEAT BUSHING
19	SEAT RING
20	STEM
21	YOKE
23	YOKE BOLT
25	YOKE BUSHING

FIGURE 2-25. OUTSIDE SCREW AND
YOKE GATE VALVE

PART	
1	HANDWHEEL NUT
2	HANDWHEEL
3	STEM
4	YOKE BUSHING NUT
5	YOKE BUSHING
6	YOKE BONNET
7	GLAND STUD NUT
8	GLAND
9	GLAND STUD
10	PACKING
11	BONNET BOLT NUT
12	BONNET GASKET
13	BONNET BOLT
14	DASH POT
15	PISTON RINGS
16	PISTON
17	LOCK NUT
18	DISC
19	DRAIN PLUG
20	SEAT RING
21	BODY
22	LUBRICATION PLUG

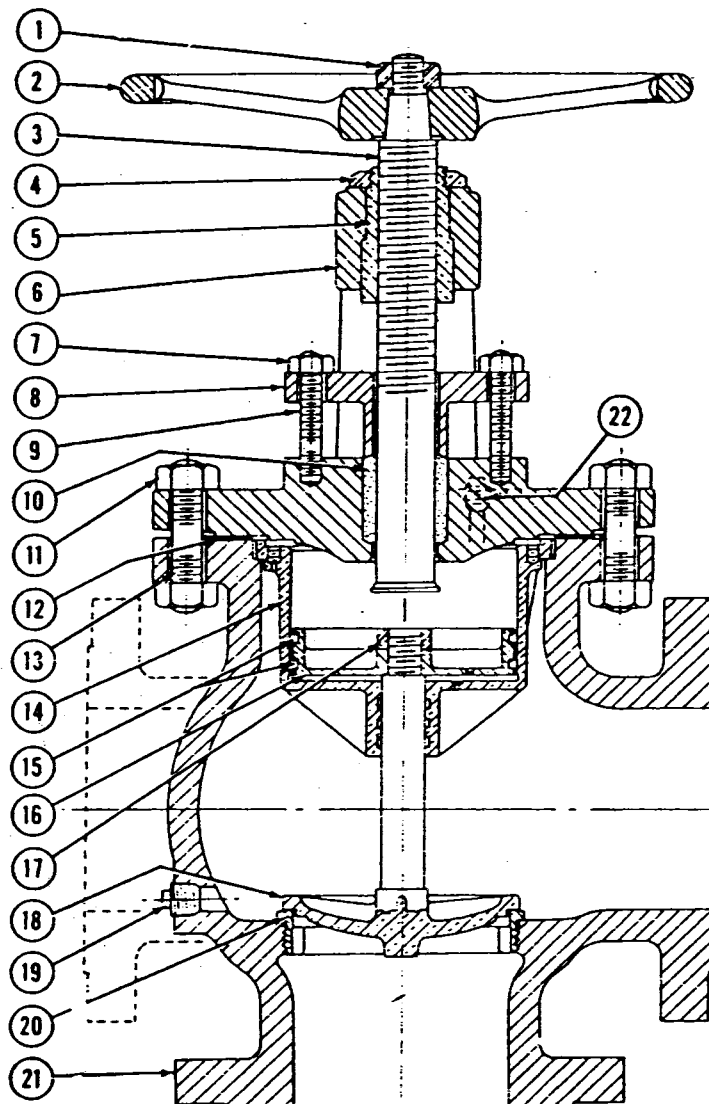


FIGURE 2-26. NON-RETURN VALVE

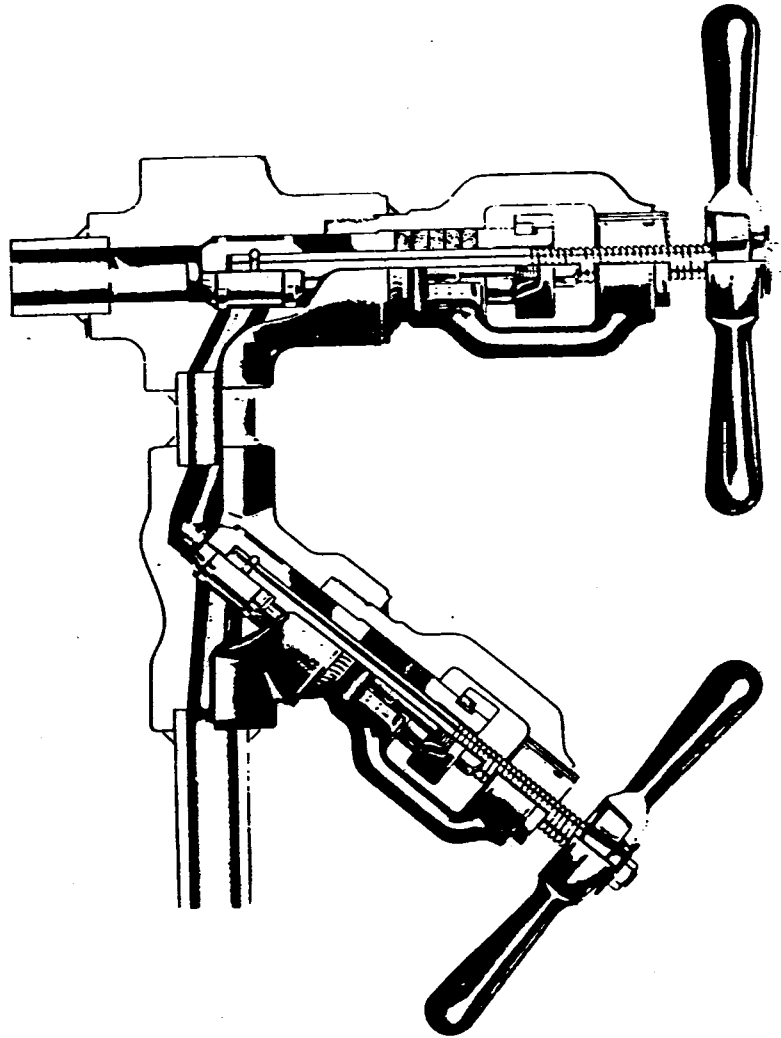


FIGURE 2-27. SLOW OPENING BLOWDOWN VALVE SET

melts the plug and steam blows out, warning the operator. This type of plug can be replaced without taking the boiler out of service, by closing the valve in the plug line.

2-17. SOOTBLOWERS.

Soot, fine ash, and cinders can collect on boiler tubes and cause a substantial decrease in the heat transfer rate. These substances are very poor conductors of heat; in addition, when excessive amounts are deposited on the tubes, passages become plugged and gas flow is restricted. Brushes, scrapers, hand lances and occasionally sootblowers are used to remove these deposits in fire tube boilers. Hand lances and mechanical sootblowers are used to clean water tube boilers.

a. Brushes, Scrapers, and Hand Lances. Brushes and scrapers are made in various sizes to fit the boiler tubes. They are fastened to a long handle, usually a piece of pipe, and pushed through the tubes. Automatic brushing systems with vacuum dust-collecting attachments are effective and common. Figure 2-28 illustrates a fire tube cleaning system. The hand lance is a piece of pipe supplied with compressed air or steam. Occasionally, a special head is attached to the hand lance. The hand lance may be needed to remove deposits of ash or slag even on boilers equipped with mechanical sootblowers.

b. Mechanical Sootblowers. Permanently mounted mechanical sootblowers are used on water tube boilers. These blowers are mounted on the setting walls or boiler-supporting structure at several points, to clean as much of the surface as is practical. Blowers consist of a head which admits steam or air and turns the element, the element itself which distributes the steam or air, and the necessary bearings, piping, and other supports.

(1) **Head.** The head consists of an operating mechanism, usually a chain or handwheel operating two gears, for turning the element within a limited arc; a poppet valve for admitting and controlling the flow of steam or air to the element; and a cam for opening and closing this valve (reference figure 2-29). The poppet valve is adjusted at startup to obtain proper steam or air regulation. The cam is cut or adjusted to establish the proper blowing arc and prevent steam or air from striking and cutting the baffles, drums, tubes, or headers.

(2) **Elements.** Elements are tubes containing a number of nozzles. These nozzles are spaced along the element to blow between the boiler tubes for lane blowing, or at a number of tubes for mass blowing. When elements are installed for lane blowing, it is important that the nozzle spacing fit the boiler-tube spacing and that the elements are located properly. Failure to observe these precautions may result in cut tubes because of the high velocity of discharge from the nozzles. The elements are made of plain,

carborized, or alloy steel, depending on the temperature to which they are to be subjected; they are supported at regular intervals by bearings clamped on the boiler tubes. The distance between these bearings is determined by the flue-gas temperature in that specific area.

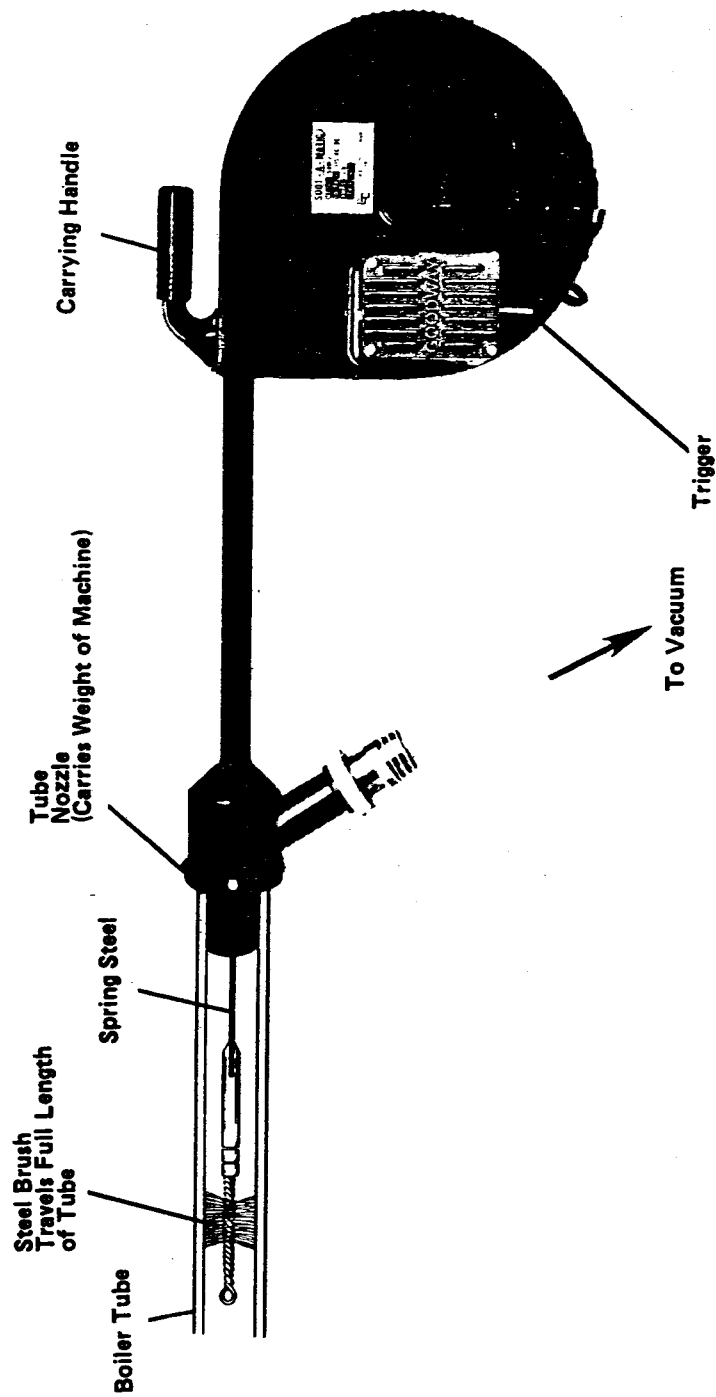


FIGURE 2-28. FIRE TUBE CLEANING SYSTEM

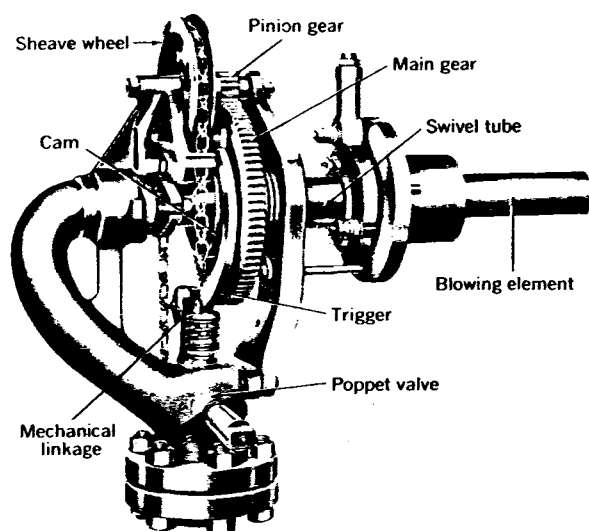


FIGURE 2-29. FIXED POSITION
MECHANICAL SOOTBLOWER

SECTION III. FUEL-HANDLING AND COMBUSTION EQUIPMENT

2-18. COAL COMBUSTION EQUIPMENT.

Coal may be fired by one of four methods:

- Manually on stationary grates
- Automatically by stoker
- In suspension as pulverized coal
- In a fluidized bed

Manual firing of coal using stationary grates is not used in modern central heating plants because of the limited capacity of hand-fired grates and the amount of labor necessary to operate the equipment. This TM contains no further discussion of manual firing. The following paragraphs describe the combustion equipment required for the other methods of coal firing and typical coal specifications applicable to each method.

a. Stokers. Stokers were developed to automate and increase the capacity of the simple hand-fired grate. Automatic fuel feed and ash disposal systems were added to reduce the labor requirements, and capacity was increased by the addition of forced draft fans, control dampers, and air compartments to promote better fuel and air mixing. The result is that stokers have several advantages over hand firing: they permit the use of cheaper grades of fuel, maintain better furnace conditions, increase combustion efficiency, require less labor, and increase the boiler capacity. Stokers may be divided into four general classes: underfeed, spreader, traveling or chain grate, and vibrating grate. Spreader, traveling, chain, and vibrating stokers are overfeed stokers, in that fuel is fed from above the bed. Each type has its own application, depending primarily on the characteristics of the fuel used. The choice of the proper stoker also depends upon factors such as the size and capacity of the boiler, the ash content and clinkering characteristics of the fuel, and the amount of draft available.

b. Underfeed Stokers. Underfeed stokers receive their name from the fact that fresh fuel is supplied below the burning zone. The fuel bed consists of three zones: fresh or green coal on the bottom, the coking zone in the middle, and the incandescent or burning zone on the top. Fresh fuel enters the bottom of one end of a retort, is distributed over the entire retort, and is forced to move gradually to the top where it burns. As the coal travels up from the bottom of the retort, its temperature gradually rises, causing the volatile matter to distill off, mix with the air supply, and pass up through the hotter zones of the fuel bed. The temperature of the mixture of volatile matter and air gradually increases until the mixture ignites and burns. The mixture may burn just below the surface of the fuel bed or immediately above it. The coke remaining

after the volatiles have distilled off continues to move to the top; its temperature gradually rises above its ignition temperature and burns. The vertical movement of the coal through the bed is accompanied by movement of the burning coke toward the ash discharge area. The combustion process is practically completed by the time the remaining material reaches this area. The remaining combustible matter or fuel completes its combustion in this area before the ash is removed. Air enters through openings in the stoker called tuyeres, which are usually located at the top or sides of the retort. Underfeed stokers may be classified by the number of retorts (single, double, or multiple) and the method of feeding (screw or ram). Single-retort stokers may be screw- or ram-feed. Figure 2-30 illustrates a single retort, screw- feed ram distributor stoker. Multiple-retort stokers usually combine a gravity or overfeed action with the underfeed, and are always ram feed. They are used only on large boilers. Coal sizing requirements are established by the stoker manufacturer, with a top size of 1½ to 2 inches and not more than 50% slack being typical. The principal elements of an underfeed stoker are hoppers, feeders, retorts, and combustion air fan. Each is discussed in the following paragraphs.

(1) **Hoppers.** Hoppers with a capacity of several hundred to several thousand pounds of coal are provided to supply fuel to the feeder. Some hoppers are equipped with agitators but most depend on the slope of the hopper sides to prevent coal from bridging. Offset hoppers are occasionally used to permit access to the boiler front.

(2) **Feeders.** Feed screws or reciprocating rams may be used to deliver coal from the hopper to the stoker retort as shown in figure 2-30. Even distribution of the coal is obtained by the shape of the screw, shape of the retort, and the stroke of the distributing rams. The coal feed rate is controlled by a drive mechanism which adjusts the speed of the screw or ram. An electric motor or steam turbine is used to drive the stoker via a mechanical or hydraulic speed reducer. Ram feed stokers may utilize oil-, air-, or steam-driven cylinders to move the ram, and are generally set up to allow multiple feed rates. Shear pins or relief valves are provided to protect the equipment against overload or binding. Belt guards and gear and shaft covers are provided for operator protection.

(3) **Retorts.** The size and shape of the retort depend on the coal-burning capacity of the stoker. Retorts in the smaller units are nearly square, while those in larger units are oblong. The tuyeres or tuyere blocks through which air is admitted to the fuel bed are made in comparatively small sections to allow for expansion and to minimize thermal stress. The tuyere blocks form the top of the retort

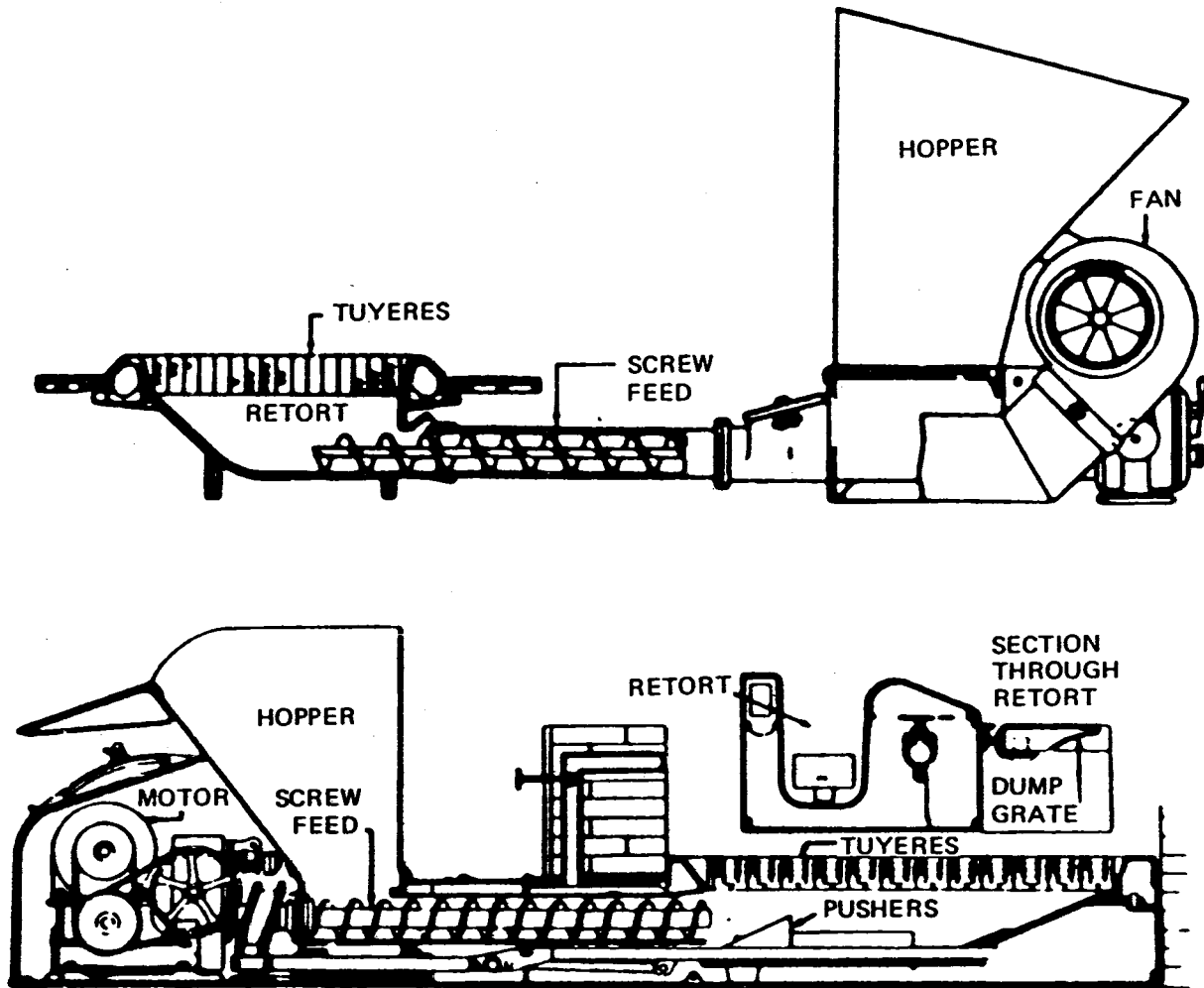


FIGURE 2-30. UNDERFEED STOKER

and are surrounded by either dead plates or dump plates. Dump plates are ordinarily made to permit air to pass through them. Tuyere blocks may be high and slope away from the retort, or recessed below the dead plate. They may be of either stationary or movable design.

(4) **Combustion Air Fan.** Centrifugal or axial fans are used to supply air to a windbox under the retort and to overfire air ports. The windbox may be divided into zones to permit better control of combustion air. The windbox may be divided into zones to permit better control of combustion air. The volume of the air supplied is controlled by inlet or outlet control dampers on the fan. Air flow should be controlled automatically to correspond to changes in the firing rate. Methods of control are discussed in paragraph 2-26.

c. **Spreader Stokers.** Spreader stokers combine some of the best features of hand- and pulverized-coal-firing methods. This method of coal feed permits smaller particles to burn in suspension in the furnace, approximating the action of pulverized-coal firing. The remainder of the coal is deposited on top of the burning coal, as in hand firing. Other similarities to pulverized-coal firing are the presence of fly ash in the flue gases, the wide range of fuel which can be handled, and responsiveness to rapid load fluctuation. Spreader stokers are not affected by the caking or non-caking properties of coal to the same extent as other types of stokers, and they can handle coal ranging in size from dust to about 1¼ inches. The furnace volume to permit fines to be burned in suspension is usually about 50 percent larger than that required for an underfeed stoker. The depth of the grate is limited by the ability of the stoker to spread coal evenly, and its width is limited by the width of the boiler; however, several stoker units can be placed side by side to provide the necessary capacity. Spreader stokers with combined traveling grates have been applied to boilers with capacities up to 400,000 pounds of steam per hour. Although the ability to burn inexpensive coal screenings is one of the chief advantages of spreader stokers, fly-ash emissions increase greatly as the percentage of fines is increased. Thus, under most conditions, spreader stokers require some type of dust collectors. All spreader stokers operate with comparatively thin fuel beds, are sensitive to load changes, and are well adapted to regulation by automatic combustion-control equipment. The thin fuel bed is a decided advantage in following fluctuating loads. Figure 2-31 illustrates a power dumping type spreader stoker. The principal elements of a spreader stoker are described below.

(1) **Feed Mechanism.** The feed mechanism consists of the feeder and the spreader. The spreader is constructed with either an underthrow or overthrow rotor. An overthrow rotor receives the coal directly and throws it into the furnace. An underthrow rotor picks coal out of

a circular tray and throws it into the furnace. Figure 2-32 illustrates an underthrow rotor. The paddles (rotor blades) are usually set in either two or four rows around the rotor, with those in one row twisted at an angle to throw the coal to the right, and those in the next arranged to throw it to the left. In some designs, the paddle is curved to provide uniform crosswise distribution. An oscillating plate or ratchet-driven roll feeder is used to supply coal to the rotor. The rate at which coal is fed is regulated by varying the length of the stroke of the oscillating plate or the speed at which the roll is turned. Speed or position adjustments are also provided to regulate the distribution of fuel along the length of the grate. The feeder mechanism, the grates, and the air supply are usually constructed to operate as a unit. The feeders are usually driven from a single line shaft, with each having its own drive gearing. When dumping grates are used, sections of the fire can be cleaned alternately by shutting off the fuel to one feeder and allowing the fuel to burn out in that section of grate before dumping. The variable speed-driven mechanisms are similar to those found on underfeed stokers. Variable speed motors often replace the mechanical gearing to drive the individual feeder and distribution shaft on newer designs.

(2) **Overfire Air Fan.** A separately driven centrifugal fan is provided to supply overfire air necessary to maintain proper fuel and air mixing and complete combustion. A portion of the overfire air may also be used to cool the feed mechanism and aid in distribution of the coal.

(3) **Cinder Reinjection System.** Since the spreader stoker burns a significant percentage of the coal in suspension, carryover of unburned coal is common. To improve boiler efficiency by reducing this unburned carbon loss, the fly ash and coal can be collected in a mechanical collector at the boiler outlet and put back into the boiler furnace. This is done by use of a cinder reinjection fan and aspirator which picks up the fly ash and coal and pneumatically conveys it back to the furnace via special piping and reinjection ports.

(4) **Grates.** Stationary, dumping, vibrating, and traveling grates may be used with a spreader stoker installation. Traveling grates are most commonly used on modern installations. Provision is made under the grates for proper air distribution and ash collection. Figure 2-10 illustrates a spreader stoker with traveling grate installation.

(5) **Combustion Air Fan.** As with all stokers, combustion air under pressure is needed to ensure complete and efficient combustion and control. Inlet or outlet dampers are provided to control the air flow rate.

d. **Traveling Grate and Chain Grate Stokers.** These type of stokers consist of an endless belt-type grate which moves slowly and conveys the burning coal from the feed end

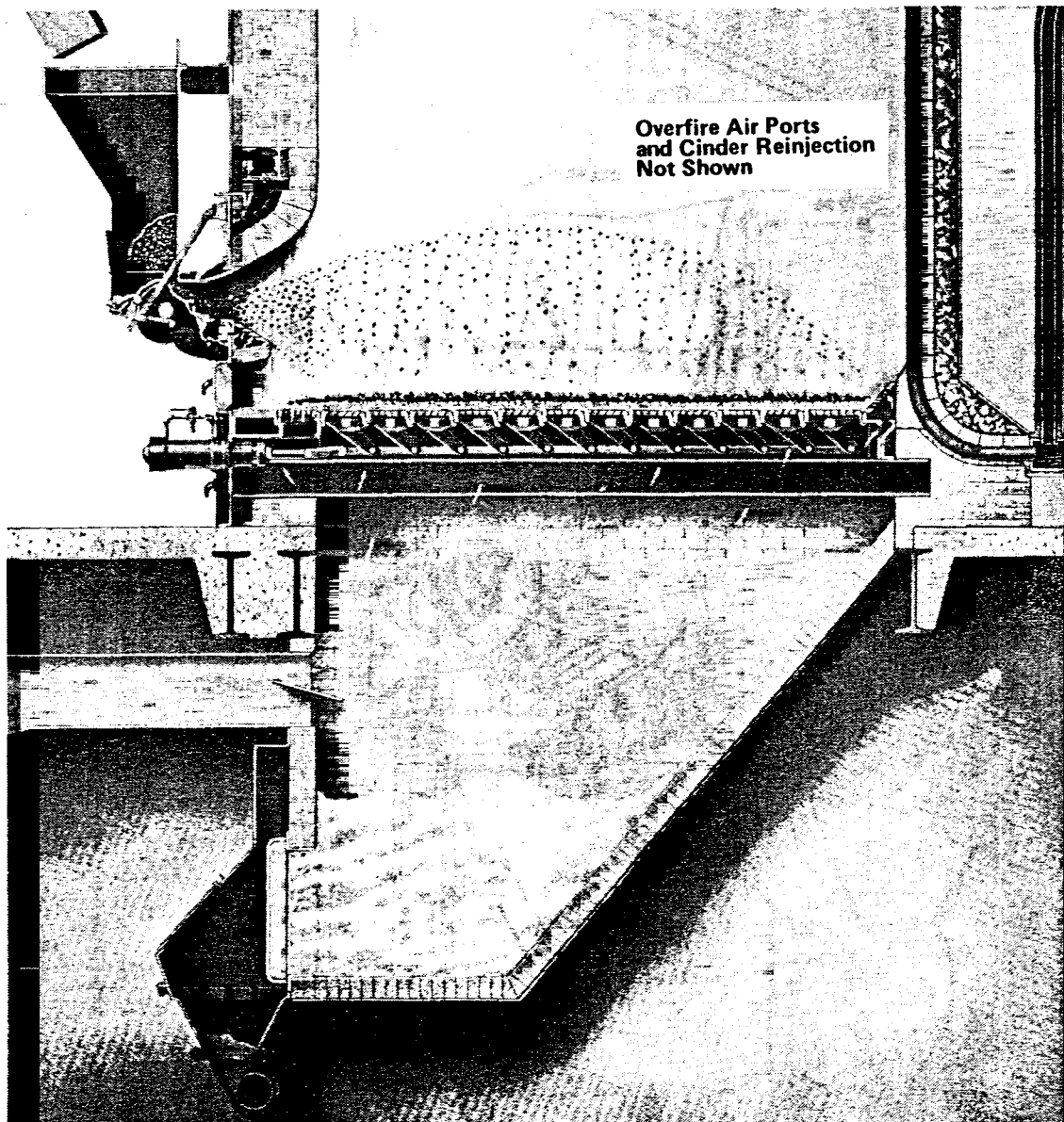


FIGURE 2-31. POWER DUMP GRATE
SPREADER STOKER

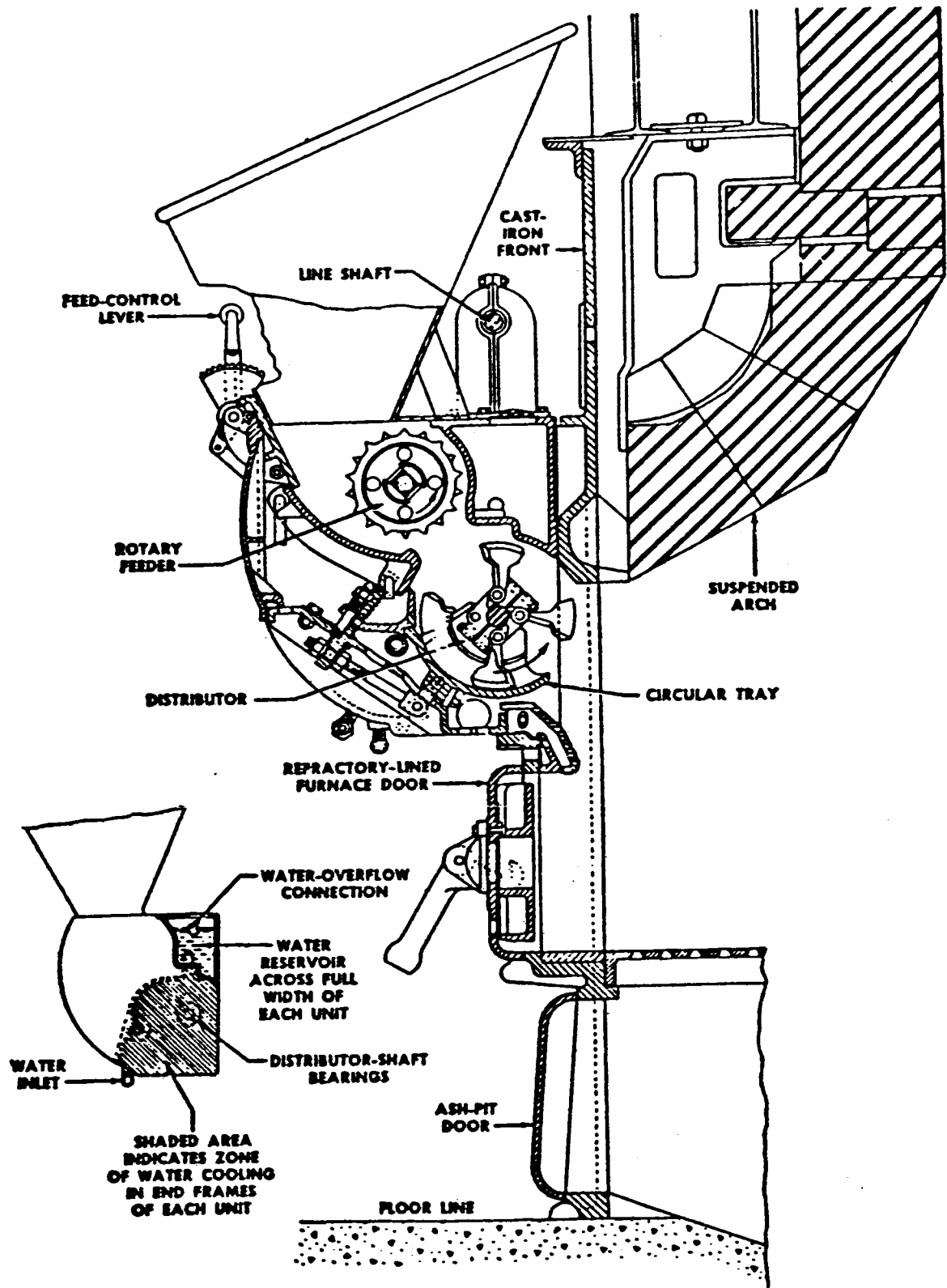


FIGURE 2-32. UNDERFEED SPREADER

to the ash discharge end of the stoker. With chain grate stokers, the links are assembled so that as they pass over the rear idler drum, a scissor-like action occurs between the links. This action helps to break loose clinkers which may adhere to the grate surface. Traveling grate stokers do not have this scissor action and therefore are not normally used with clinkering coals. Figure 2-33 illustrates a traveling chain grate stoker. Traveling or chain grates may be used with spreader feeders discussed above, or the coal may be placed directly on the stoker, as described below.

(1) **Feed Mechanism.** A hopper on the front of the stoker has an adjustable gate which regulates the depth of the fuel bed. The rate of feeding coal to the furnace is regulated by changing the speed at which the grate travels. The amount of ash carryover from the furnace is kept to a minimum with this feeding method, and fly-ash injection, typical of spreader stokers, is not required. Figure 2-33 illustrates the overfeed of coal onto a chain grate.

(2) **Combustion Air.** The space between the grates is divided into zones and the flow of air to each of these zones is controlled by dampers. This is necessary if uniform combustion is to be attained, because the resistance of the fuel bed to the flow of air decreases as the grates move to the rear. It would be practically impossible to get proper air distribution if these zones were not provided. Overfire air is also provided to complete the combustion of volatiles driven off from the fuel bed.

e. **Vibrating Stokers.** In this type of stoker the grates are inclined at an angle of about 14 degrees. Coal is fed from a hopper at the front of the furnace. The fuel bed is progressed by intermittent grate vibrations. Ash is discharged over the end of the grate (reference figure 2-34). The furnace water tubes are positioned under the stoker grates to cool the grate bars, and air compartments are provided to control combustion air. Overfire air is generally provided at two elevations. The firing rate is controlled by adjustment of a hopper feed gate, frequency of grate vibration, combustion air dampers, and overfire air dampers.

f. **Pulverized Coal.** Pulverized coal firing requires the operation and maintenance of pulverizers. Historically, it has not been economical to install pulverized coal firing systems on boilers with a steam flow of less than 100,000 pounds per hour, and they are uncommon in Army Central Heating Plants. For further information on pulverized coal systems, refer to Navy Manual MO-205, Volume One, Sections 19 and 20.

g. **Fluidized Bed.** Fluidized bed combustion is a relatively new method of burning coal while complying with sulfur dioxide emission regulations. In fluidized bed combustion the coal is introduced into a bed of limestone or sand

particles which is kept in a fluidized state by a flow of high pressure air from FD fans. Combustion takes place in the bed. The sulfur in the fuel combines chemically with the limestone in the bed, forming calcium sulphate and calcium sulphite which can be removed with the ash handling system, eliminating the need for scrubbers to clean the flue gases. The main advantage of the fluidized bed boiler is thus its ability to control sulfur dioxide emissions. However, it also has the ability to burn a wide variety of fuels as discussed below. The disadvantages of fluidized bed boilers are the added electrical operating costs associated with the larger combustion air fans necessary for fluidizing the bed, higher particulate and unburned carbon carryover from the furnace, and high initial cost. Figure 2-35 illustrates a fluidized-bed fire tube boiler. Fluidized-bed water tube boilers are also available. Note that a baghouse or precipitator is required for particulate control.

h. **Fuel Characteristics and Specifications.** The following paragraphs provide general guidelines on the types of coal which are applicable to the various firing methods. There is, however, much overlap in these guidelines, and the equipment manufacturer or other combustion expert should be consulted if a change in fuel type is considered.

(1) **Underfeed Stokers.** In practical applications, fuels ranging from lignite to anthracite have been burned successfully on single retort underfeed stokers. However, this type of stoker is most widely used for Eastern caking and mildly caking bituminous coals and many of the Midwestern free burning coals, especially those having an ash fusion temperature sufficiently high for successful utilization in the relatively thick fuel beds that characterize underfeed burning. For satisfactory stoker operation, coal sizing is as important as coal analysis. The size of coal best suited for single retort stokers is that designated commercially as 1 inch to 1½ inch nut and slack, preferably containing not more than 50% slack. Slack is defined as coal of a size that will pass through a ¼ inch round-hole screen. For multiple retort underfeed stokers the ideal coal should vary in size from 2 inch to slack, with not more than 50% slack. The volatile content should preferably be between 20 and 30%; the ash content should range between 6 and 8%, and the ash softening temperature should be above 2400 F in a reducing atmosphere. Iron content of the ash should be not more than 20% as Fe_2O_3 for this range of softening temperatures and not more than 15 percent if the softening temperature is between 2200 and 2400 F.

(2) **Spreader Stokers.** Spreader stokers were developed to burn the lower grades of coal, but they are capable of handling all ranks from semianthracite to lignite, plus numerous waste and byproduct fuels. As might be expected, spreader stoker performance is best when quality and sizing

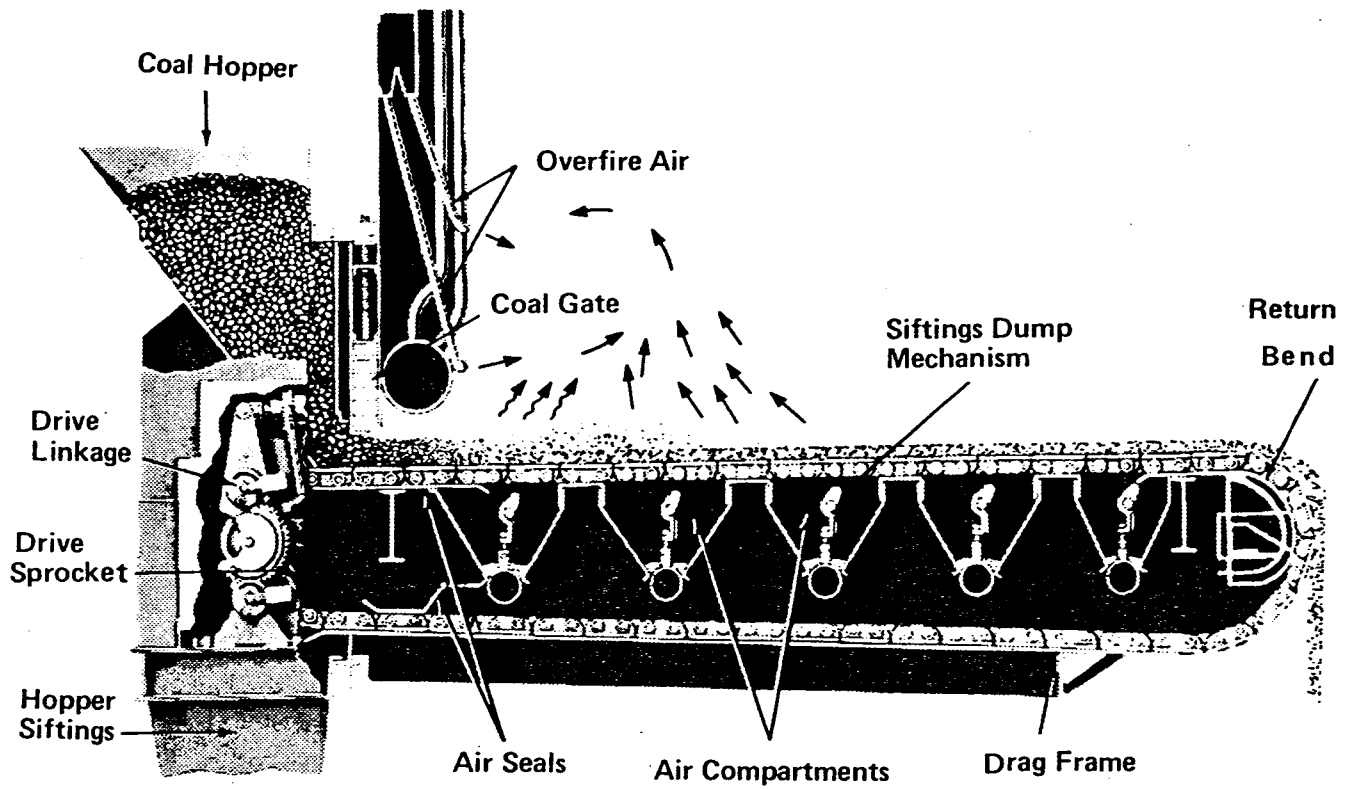


FIGURE 2-33. TRAVELING CHAIN GRATE STOKER

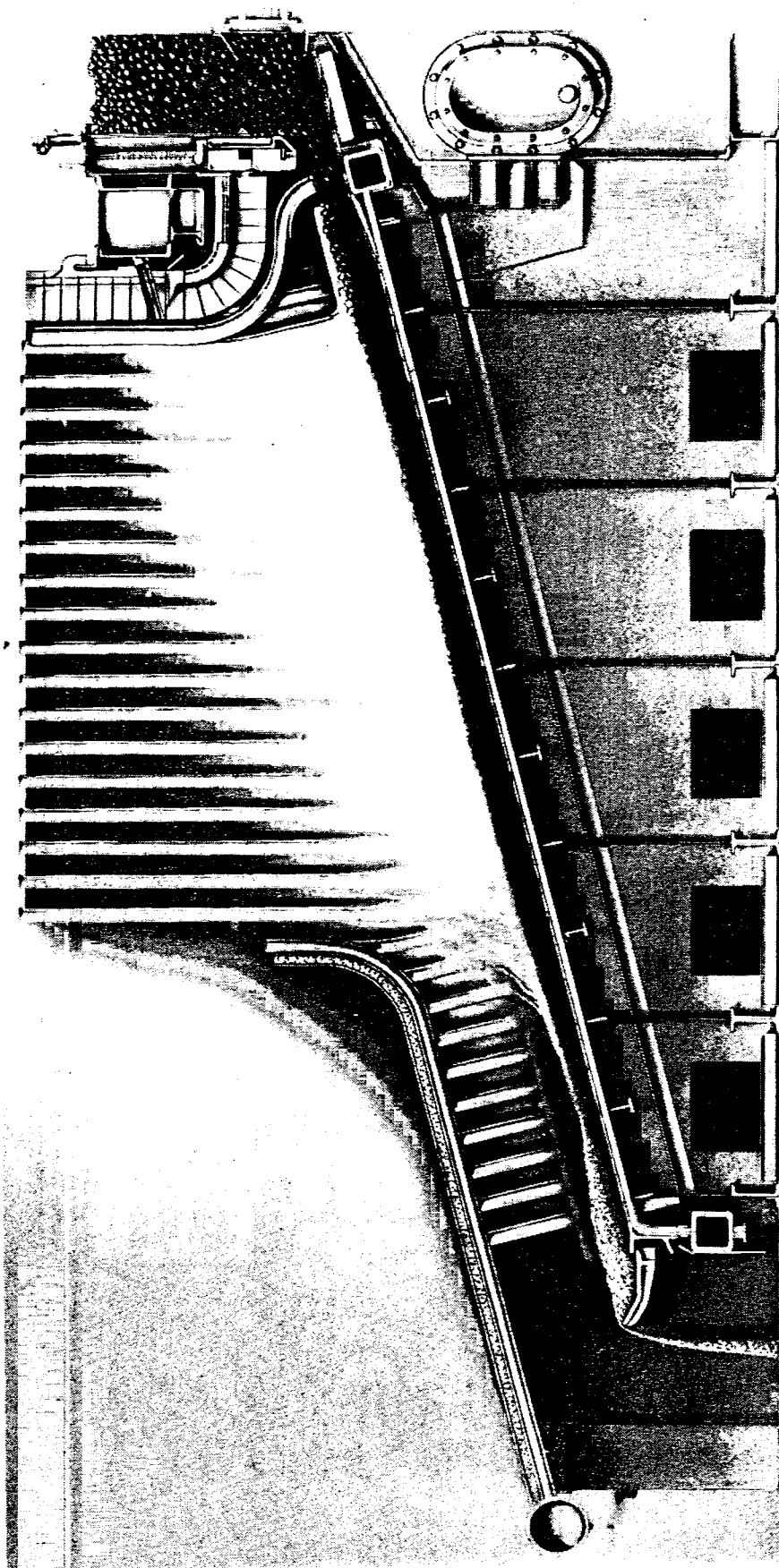


FIGURE 2-34. VIBRATING GRATE STOKER

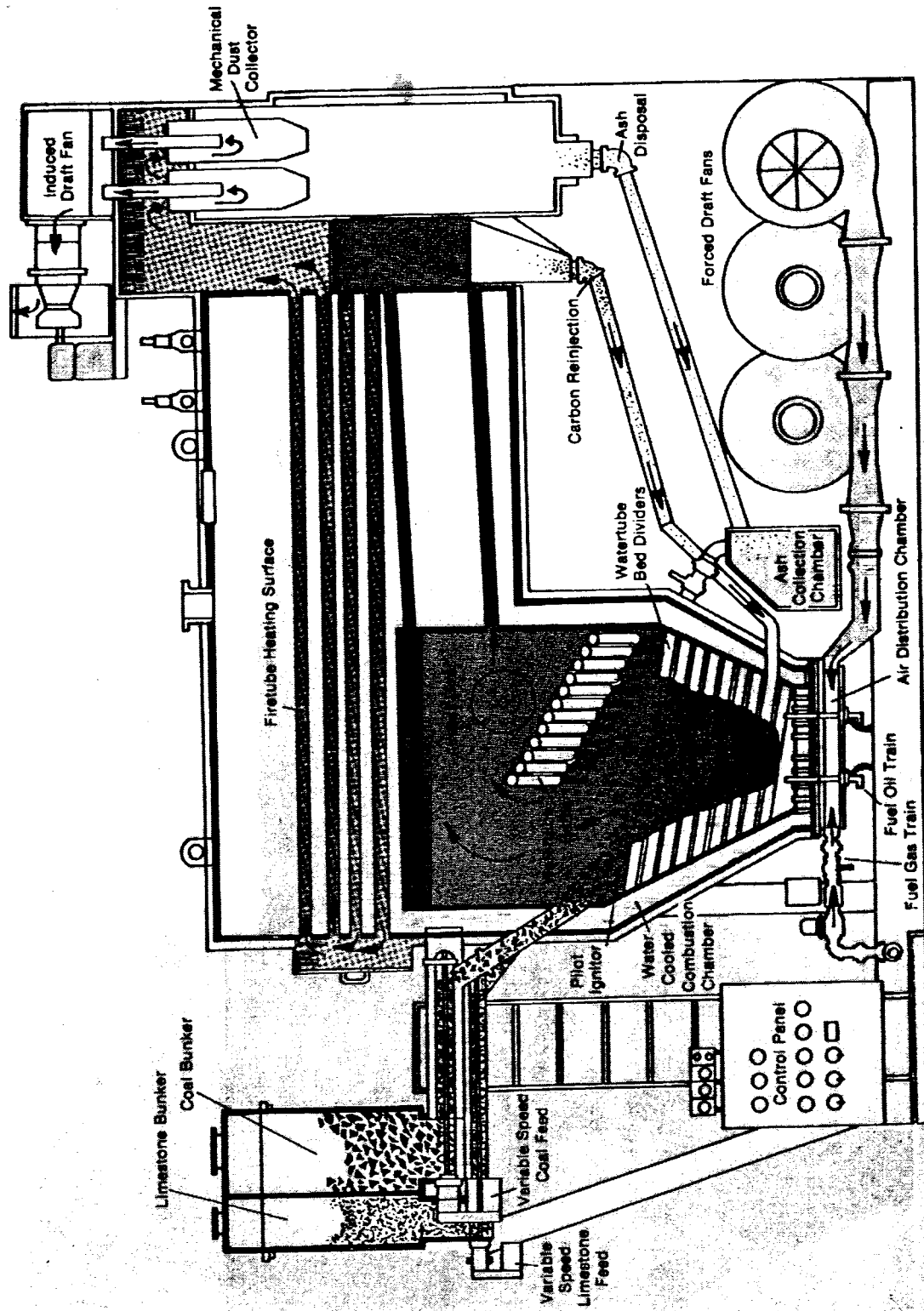


FIGURE 2-35. FLUIDIZED BED
FIRE TUBE BOILER

are good. The thin, quick burning fuel bed requires a relatively small size fuel. The spreader stoker will burn fuel ranging from slack or carbon, all through $\frac{1}{8}$ or $\frac{1}{4}$ inch screen, to $1\frac{1}{4}$ or $1\frac{1}{2}$ inch nut and slack. Considerable range in size content is necessary for satisfactory distribution, and if there is a good balance between coarse and fine particles the burning rate and ash bed thickness are practically uniform over the entire grate surface.

(3) **Traveling Grate and Chain Grate Stokers.** The fuels most widely used on traveling grate stokers are anthracite, semianthracite, noncaking or free-burning bituminous coal, subbituminous coal, lignite and coke breeze. Some bituminous coals of the caking type may be burned on traveling grate stokers if the coal is of an optimum size, has been allowed to weather, and is tempered to approximately 15 percent moisture. Coal sizing for traveling grate stokers may be related to the ASTM Classification of Coal by Rank (D-388) as shown in table 1-1. For anthracite (Rank I-2), the size of No. 3 buckwheat (barley) should be all through $3/16$ inch round hole screen and not more than 20 percent through $3/32$ inch screen; No. 4 buckwheat should pass through a $3/32$ inch round hole screen with not more than 10% through a $3/64$ inch screen and not more than 1% through a 100 mesh screen. For coals of ASTM Ranks II-4, 5, III-1, 2, 3, and IV-1, 2 the size should be 1 inch nut and slack with not more than 50% slack through a $\frac{1}{4}$ inch round-hole screen and tempering to 15% moisture. For friable coals of ASTM Ranks II-1, 2, 3, the sizing should be $1\frac{1}{4}$ or $1\frac{1}{2}$ inch nut and slack with not more than 50% slack through a $\frac{1}{4}$ inch round screen. For nonfriable coals of ASTM Ranks II-1, 2, 3, the sizing should be $\frac{3}{4}$ inch nut and slack with not more than 50% slack through a $\frac{1}{4}$ inch round-hole screen. If coke breeze is burned on traveling grate stokers, it should contain 8 to 10% moisture and not less than 1% volatile matter; the entire quantity should pass through a $\frac{3}{8}$ inch round mesh with not more than 50% or less than 25 percent through a $\frac{1}{8}$ inch round-hole screen.

(4) **Vibrating Grate Stokers.** The water-cooled vibrating grate stoker is suitable for burning a wide range of bituminous and lignite coals. Even with coals having a high free-swelling index, the gentle agitation and compaction of the fuel bed tends to keep the bed porous without the formation of large clinkers generally associated with low ash-fusion temperature coals. A well-distributed, uniform fuel bed can be maintained without blow holes or thin spots.

(5) **Fluidized Bed.** Fluidized bed boilers may be used to burn almost any fuel, including not only bituminous and anthracite coals but also lignite, refuse, wood, and various solid waste fuels.

2-19. COAL-HANDLING EQUIPMENT.

A great many types of coal-handling equipment with capacities ranging from a few tons to several hundred tons per hour are available. The kind of equipment selected is determined by such factors as size of plant, total amount of fuel to be burned, method of receiving the coal (rail, truck, or water), regularity of delivery, kinds of coal available, and relative locations of the plant and storage areas. It is usually advantageous to keep a certain amount of coal in storage, in case deliveries are delayed for any reason. The amount of coal stored depends on the rate at which it is burned, space available for storage, and frequency of delivery. The quantity stored should normally be sufficient to operate for 90 days or longer at peak demand.

a. **Storage.** Coal may be stored in covered bins or bunkers, in silos, or in the open. Only relatively small amounts can be stored in bunkers and silos. The amount that can be stored on the ground is limited only by the space and coal handling equipment available. If coal is to be stored on the ground, the selected area should be prepared to reduce loss of fuel due to mixing with foreign material. The site may be leveled and firmly packed, stabilizing materials may be used, or a concrete or asphalt surface may be laid. Silo storage is divided between live and dead storage. The dead storage in silos should be shifted at least once per month. Where obvious heating occurs, shifting of dead storage should be as often as required to minimize spontaneous heating and to avoid fires. For additional information, see TM 5-675 concerning handling, storing, and sample preparation.

b. **Coal Handling in Plant.** Figure 2-36 illustrates a system typical of those found in Army Central Heating Plants. It includes the following major components: track or truck hopper, feeder, bucket elevator or conveyor, bunker or silo, and coal weighing device.

(1) **Hoppers.** Hoppers receive coal from trucks or coal cars and deliver it to a feeder or conveyor system. Hoppers usually have grates made of steel rods or bars to prevent passage of oversized material which could plug or damage the conveying equipment.

(2) **Feeders.** Many types of feeders are available to convey and regulate the flow of coal from the hopper to the bucket elevator or other parts of the system. Apron feeders and flight feeders are continuous chain-type feeders which are often used. Final selection is dependent on the particular site characteristics.

(3) **Bucket Elevators.** A bucket elevator consists of an endless chain, twin chains, or belt to which buckets are attached. It is used to lift coal vertically. The three most common types of bucket elevator discharges are centrifugal, perfect, and continuous (reference figure 2-

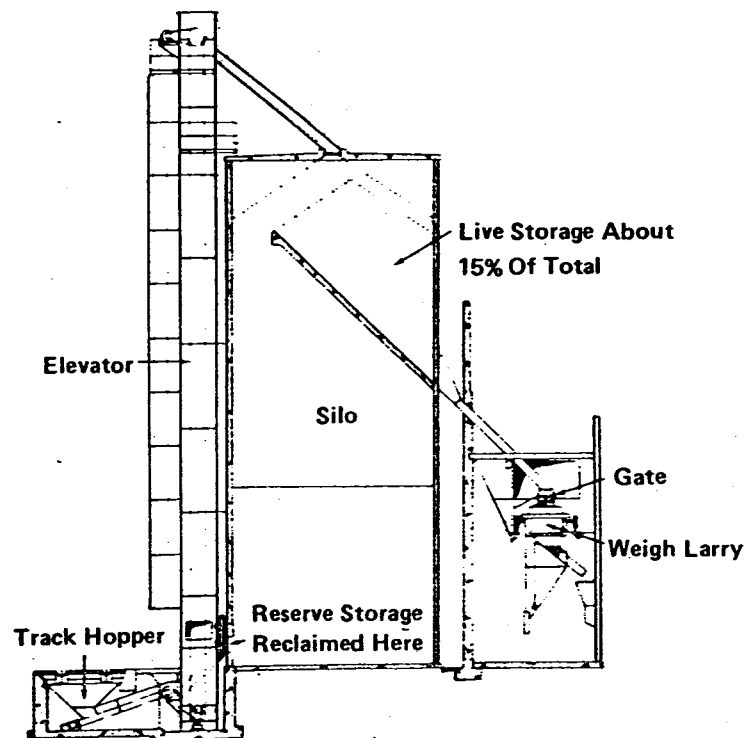


FIGURE 2-36. COAL HANDLING SYSTEM

37). Elevator boots are provided with clean-out doors for removing dropped coal. Some bucket elevators can also convey coal horizontally. Belt conveyors and drag-type flight conveyors are other effective devices for delivering coal to bunkers.

(4) **Bunkers and Silos.** Bunkers and silos provide covered storage of the coal. Bunkers are made of steel and are often lined with a protective coating to minimize corrosion and abrasion. Hopper bottom and discharge gates are provided to remove coal from the bunker. Silos are constructed of either steel or concrete and are often provided with live storage sections and reserve storage sections.

(5) **Coal Weighing.** A knowledge of the quality and quantity of coal used is essential for efficient operation of a boiler plant. No standard method of weighing coal can be prescribed, since many types of equipment are available for doing the job manually or automatically. Coal may be weighed directly with weighing equipment, or indirectly with equipment which measures its volume. Weighing equipment ordinarily consists of automatic or semiautomatic weigh larries. As shown in figure 2-38, a weigh larry consists of a framework which supports a hopper mounted on scale beams. The framework can be moved over the various bunkers. The coal hopper of the larry is filled and the weight determined and recorded. The larry is then moved to the desired stoker hopper and dumped. Coal scales which weigh coal automatically are also available. One type of scale consists of three major assemblies: a belt feeder, a weigh hopper with bottom dump gate, and a weigh lever with controls. A mechanical register is provided to record the amount of coal delivered. A belt feeder transfers the coal into the weigh hopper until the weigh lever is balanced. The weigh hopper is then dumped and the cycle is repeated.

2-20. ASH-HASNDLING EQUIPMENT.

Ash typically requires removal from several collection points in the boiler. Ash that is removed directly from the furnace or stoker is termed "bottom ash" and may be in hard, agglomerated clinkers. Ash that is removed from various dust collection points is termed "fly ash" and tends to be light, fluffy, and relatively free flowing. All the ash is generally handled together and disposed of in a permitted landfill, especially on small systems. Depending on individual circumstances, it may be desirable to segregate the bottom and fly ash and handle them separately. This could be advantageous, for instance, if a commercial market existed for one of the products. (Fly ash may be used in the manufacture of concrete; bottom ash may be used as a winter road treatment, etc.) Medium-size and large plants generally employ complete ash disposal

systems, while small plants may use simpler and less automatic equipment. The three general types of ash-handling systems are pneumatic, hydraulic, and mechanical. Combinations of these three systems are often used.

a. Pneumatic Ash Handling. Figure 2-39 illustrates a vacuum-type pneumatic ash-handling system. In this illustration, the vacuum is created by a steam exhauster; however, motor-driven vacuum pumps are also available. Intake hoppers provided at desired locations admit the ash to the system. One end of the ash-conveying line is open, and the suction created by the exhauster causes a rapid flow of air through the line. Dry ash is admitted to the primary and secondary ash receivers, which are equipped with counterbalanced drop doors. A timer limits the period of operation to short cycles to permit dumping the ashes into the silo. As the system goes into operation the negative pressure in the receivers closes and seals the drop doors. At the end of each cycle, the doors swing open when the pressure is equalized, and drop the ashes into the silobelow. The air washer condenses the incoming steam from the exhauster, washing out ash and dust particles entrained in the air stream. Clean air is thus exhausted to the atmosphere. The mixture of water and dust passes to a sump, where the dust settles and the water is drawn off to waste. It is necessary to clean the sump periodically to prevent clogging the sewer. An exhaust silencer is available for this system where desired. An unloader is usually provided and consists of an inclined revolving drum containing water sprays which wet the ashes as they are discharged from the bottom of the silo. Vacuum systems are limited in the distance which they can move ash effectively, and pressurized pneumatic systems or combination vacuum/pressure systems are available if the conveying distances become too great. Pneumatic systems are most commonly used for conveying fly ash but are also occasionally used for bottom ash on small systems.

b. Hydraulic Ash Handling. Figure 2-40 illustrates a hydraulic ash-handling system. This is a pressure velocity system in which the otivating force is provided by a ser.es of high-pressure water jets. When the system operates, the ash is taken from the ash jet hopper beneath the boiler. Sprays and water jet nozzles flush the material out of the hopper and through a grid which retains any large clinkers for breaking. Some systems are equipped with clinker grinders. The ash is then jetted through an abrasion-resistant sluice gate to a sump pit or a landfill. The fly ash and dust are aspirated pneumatically from the dust hoppers by water jet exhausters and passed through an air separator where the air is collected and vented to the atmosphere. Finally, the mixture of fly ash, dust, and water is discharged through the sluice gate to the sump pit or landfill. Hydraulic systems are normally used for bottom ash conveying. They are used infrequently on new

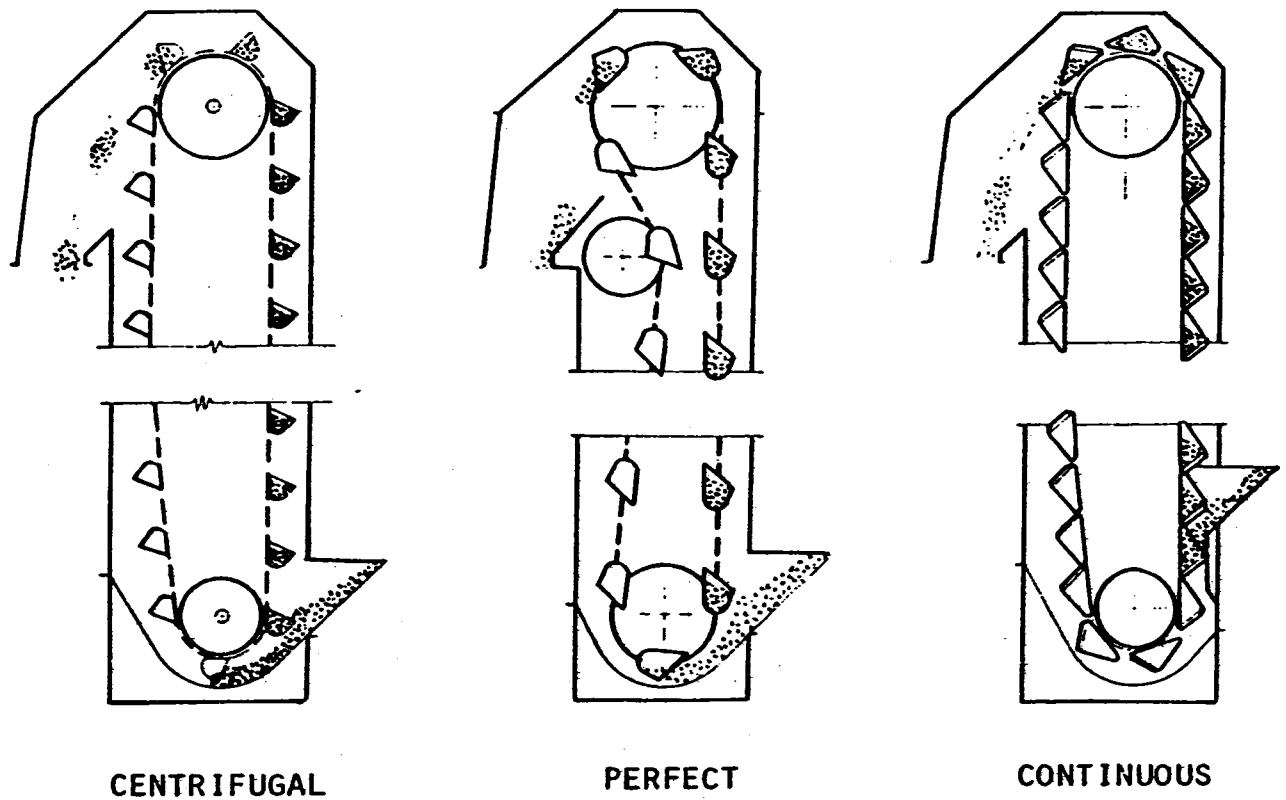


FIGURE 2-37. TYPES OF BUCKET ELEVATORS

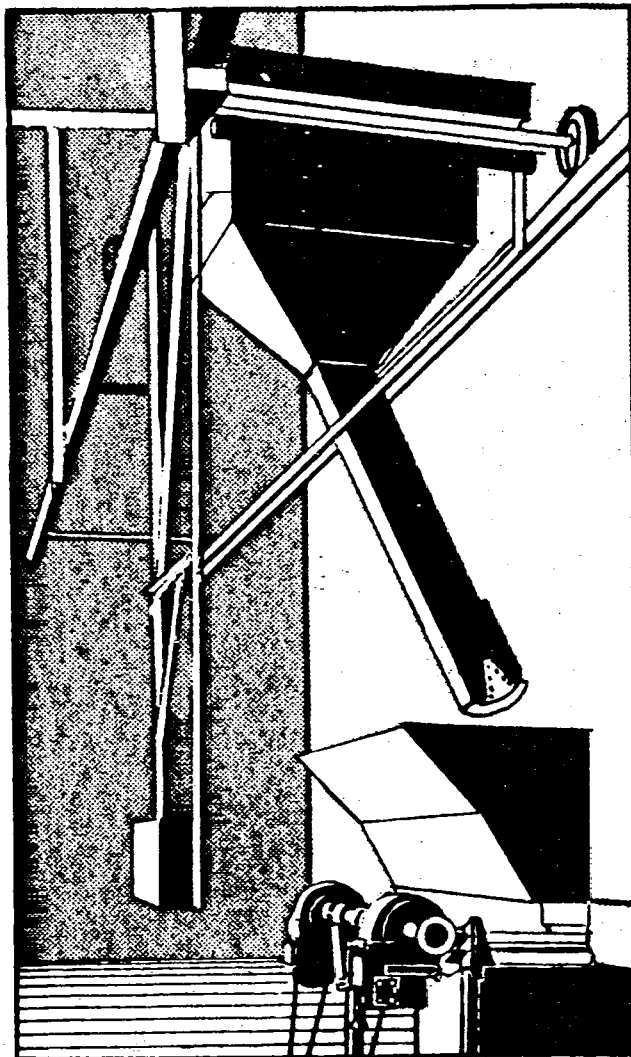


FIGURE 2-38. WEIGH LARRY

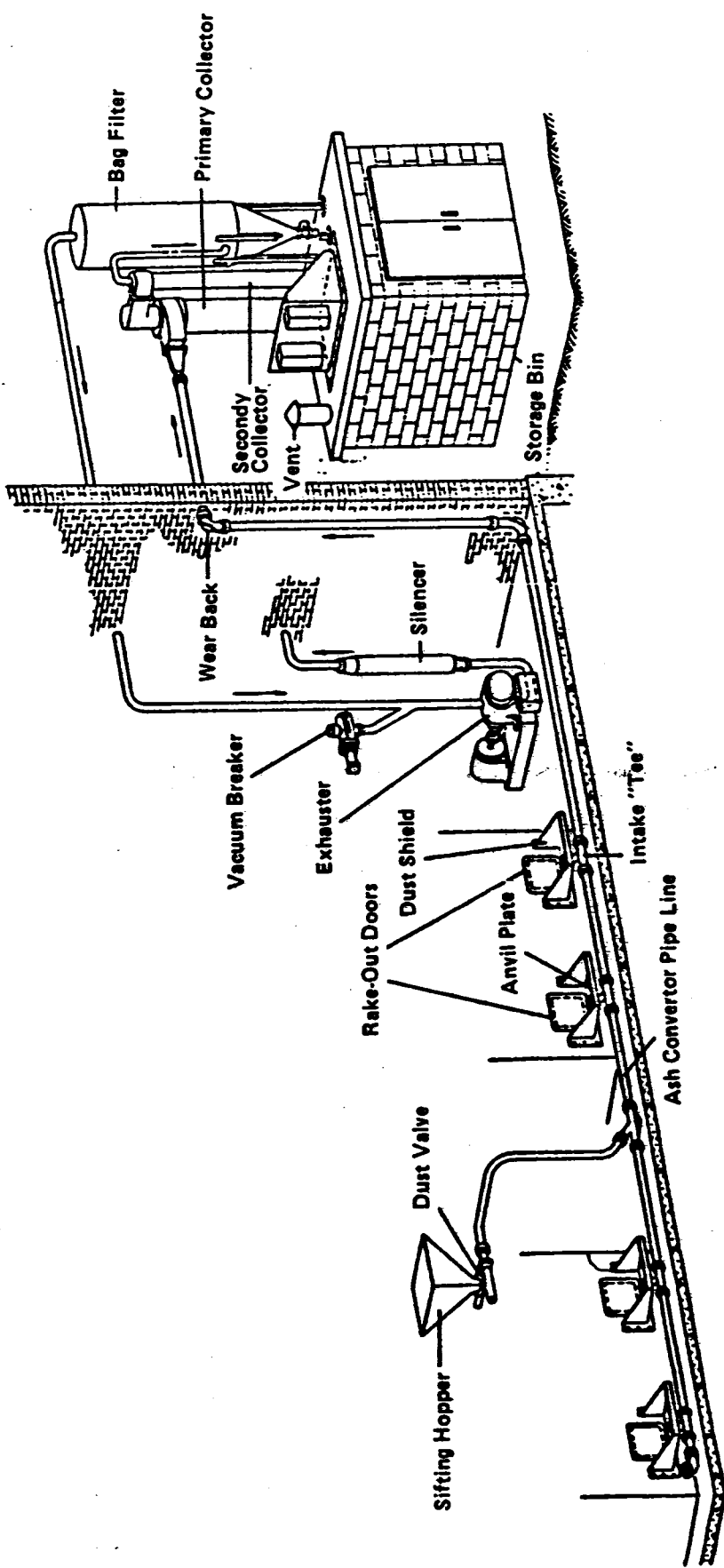


FIGURE 2-39. PNEUMATIC ASH HANDLING SYSTEM

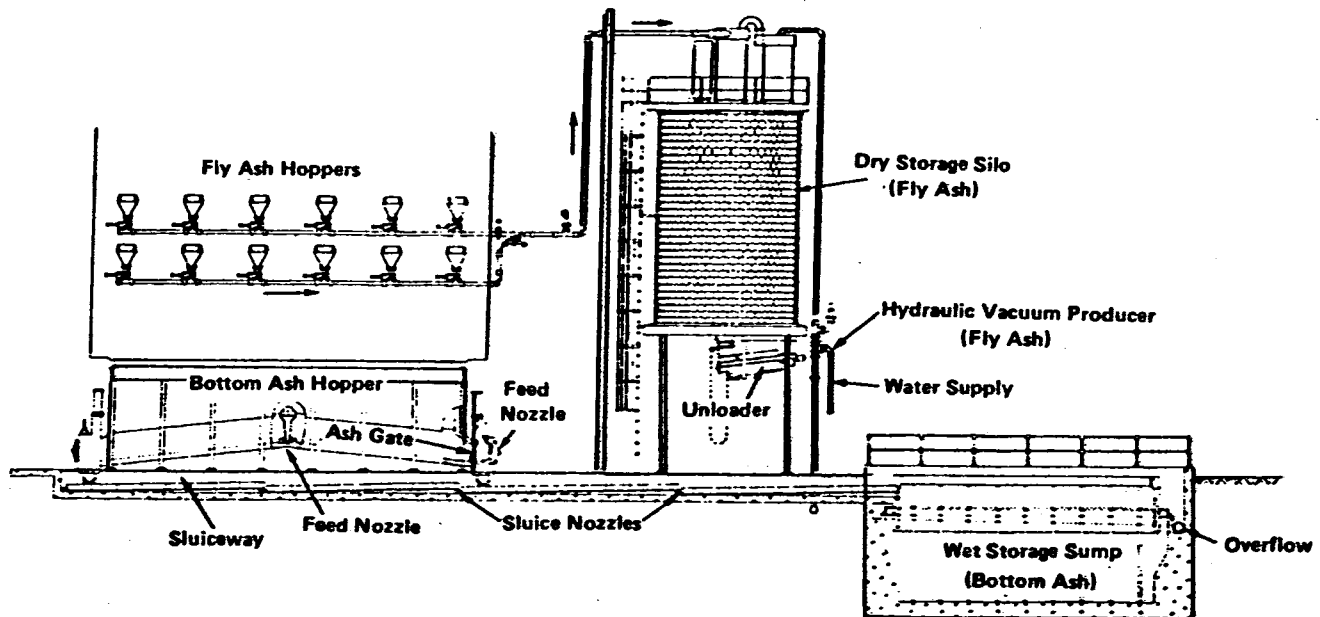


FIGURE 2-40. HYDRAULIC ASH HANDLING SYSTEM

installations due to environmental and water usage regulations.

c. Mechanical Ash Handling. Drag, screw, and bucket conveyors can be used to move ash from the boiler ash pits to storage bins, silos, or containers. Mechanical systems are used primarily with small stoker fire boilers, and may be utilized for either bottom ash or fly ash.

2-21. OIL-FIRING EQUIPMENT.

Oil has a number of advantages over coal when used to generate steam or hot water: the cost of fuel handling is lower, less labor is required for operation and maintenance, less storage space is required, the initial cost of the oil system is lower, and higher efficiencies are possible. In addition, oil does not normally deteriorate in storage; it is a clean-burning fuel and is easy to control. A disadvantage of oil is the greater danger of explosions which leads to more elaborate flame safety controls, and its cost, which is two or three times higher than coal on a heating value basis. Refer to paragraphs 1-4b and 1-8 for a more detailed discussion of fuel oil and the combustion process and to table 1-3, which presents the physical properties of common grades of fuel oil. The operator should be familiar with the fundamental principles of combustion to make best use of this concentrated and valuable fuel.

a. Types of Oil Atomizers. Burners in Central Heating Plants utilize three types of atomizers: atomizers using steam or air, pressure atomizers, and rotary cup atomizers. The purpose of atomization is to break the fuel into fine particles that readily mix with combustion air. The fuel then burns with a clean hot flame, being vaporized and oxidized by the resulting combustion before cracking takes place. In pressure atomizing burners the fineness of spray increases as pressure increases and as viscosity is lowered. When No. 6 oil is burned, a pulsating flame may result if viscosity is reduced to a point where the preheat temperature tends to vaporize the fuel. The burner manufacturer should recommend a proper viscosity range at which to operate. Proper preheating of oil will be discussed in paragraph 3-17.

(1) Fluid Atomizers. Fluid atomizers use either steam or air to break the fuel oil into a fine mist. Steam atomizers operate by mixing the oil and steam inside the atomizer tip under pressure. As the steam and oil mixture leaves the tip, the steam rapidly expands, breaking the oil into small droplets to begin the combustion process. Figure 2-41 illustrates a steam atomizer. Steam is supplied to the atomizer at a pressure of between 10 and 20 psi above the oil pressure. Under normal conditions, a steam atomizer uses approximately one-tenth pound of steam to atomize one pound of oil. This amounts to about 2/3 of 1 percent of the boiler steam output. Some modern atomizers use

as little as 0.03 pounds of steam while older designs may use more steam. Compressed air may also be used in place of steam to atomize oil. An air atomizer uses energy developed by the air compressor to replace energy in the steam generated in the boiler. Air atomizers are commonly used when steam is not available, on smaller boilers generating less than 20,000 pounds of steam per hour, and for firing more easily atomized oils, such as No. 2 and No. 4 grades. Air atomizers are often used for cold startup of a boiler, then replaced by steam units as the plant pressure builds up. Both steam and air atomizers are effective when used with a good burner to control combustion air mixing. Automatic control of firing rate is possible over a range of 15 to 100 percent of capacity.

(2) Pressure Atomizers. Pressure atomizers use pressures of 600 psig or more to accelerate the oil into the furnace through the atomizer tip. The oil is spun inside the tip and leaves as a cone of oil which thins out and breaks apart into fine droplets for combustion. The advantage of pressure atomizers is the simplicity of the system. The disadvantages are the high pressure required and the fact that turndown range is limited to 75 to 100 percent of capacity if effective atomization is to be maintained. This type of atomizer is also sensitive to oil viscosity, and the small passages in the atomizer tips tend to clog and wear. Pressure atomizers are not frequently used on modern Central Heating Plants. **(3) Rotary Atomizer.** The rotary atomizer uses the energy from a spinning cup and primary air from a small fan (reference figure 2-42). A thin cone of oil is spun off the end of the cup and, aided by the primary air, thins out and breaks apart into fine droplets. Rotary atomizers can be fairly effective when combined with burners using forced draft fans. Natural draft rotary atomizer burners as developed in the 1930s do not compare favorably with modern forced draft burners and, in general, rotary atomizers do not have any significant advantages over fluid and pressure types. They have the disadvantages of limited capacity and electric horsepower requirements for driving the rotary cup and the primary air fan. They generally become uneconomical for boiler capacities above 20,000 pounds of steam per hour, and are seldom used in modern burners. Figure 2-42. Rotary Atomizer

b. Types of Burners. Once the oil is effectively atomized, the next step is to effectively mix it with the combustion air. Three general types of burners are available: register, low excess air, and package burners. All of these burners incorporate an igniter for automatic light-off and provision to mount flame scanners to prove igniter and/or main flame. Effectiveness of a burner is measured by its ability to complete combustion of the fuel with a minimum of excess air throughout the firing range. Excess air levels at 100, 75, 50, and 25% load should be determined when

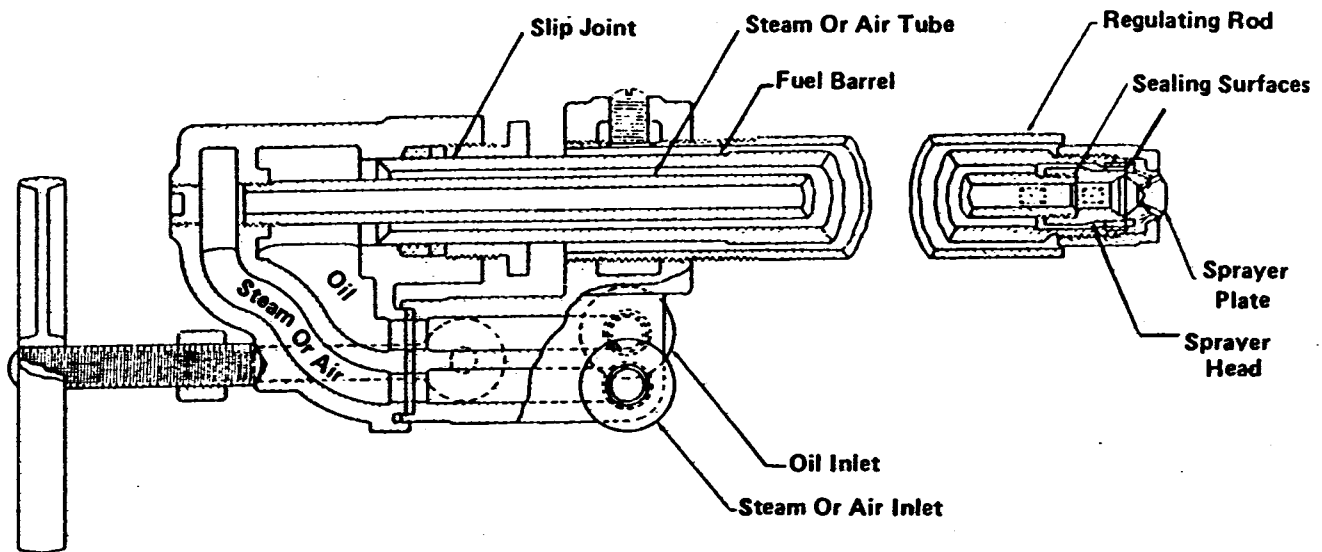


FIGURE 2-41. STEAM ATOMIZER

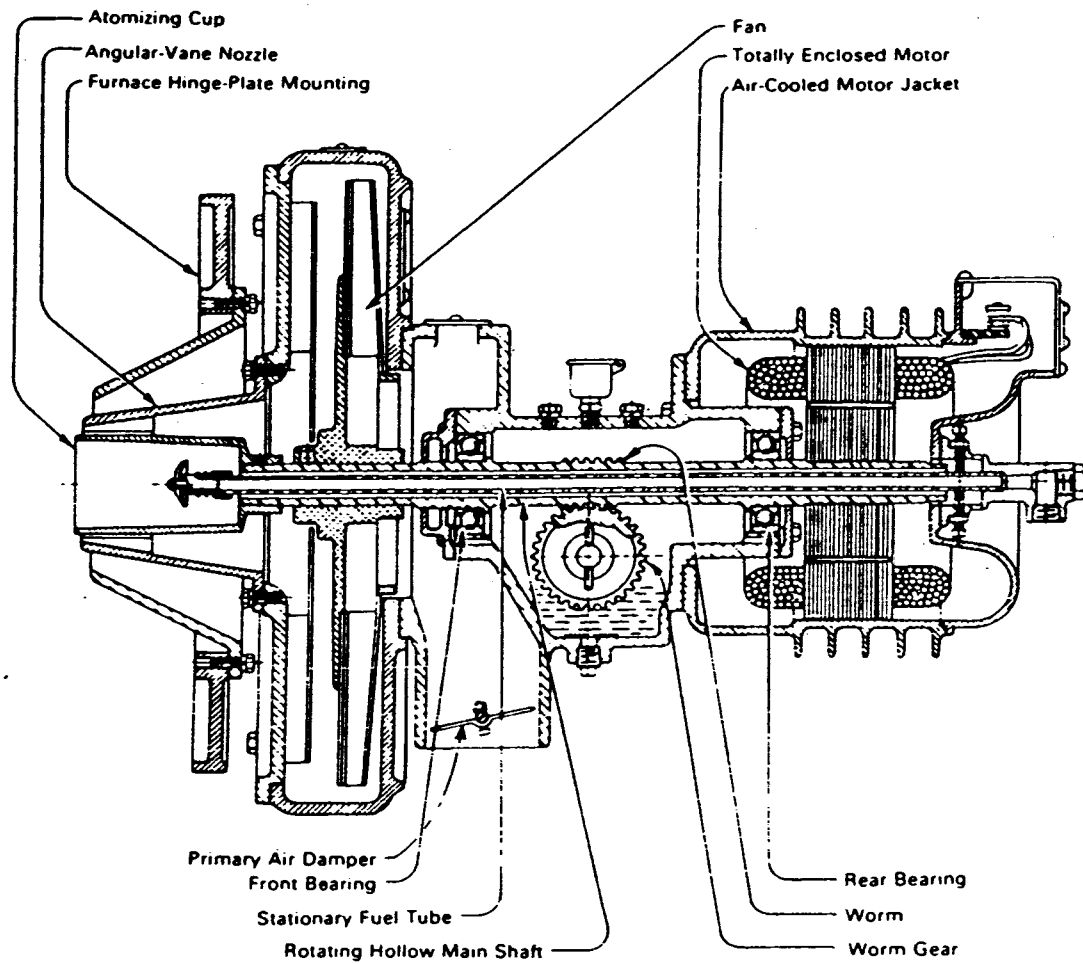


FIGURE 2-42. ROTARY ATOMIZER

evaluating burner effectiveness. Reference paragraph 3-34 and table 3-1 for more information.

(1) **Register Burners.** Register burners are characterized by one or more circular registers which admit combustion air into the burner throat as illustrated in figure 2-43. An impeller is provided to protect the atomizer from the direct blast of the combustion air and to provide a zone to stabilize ignition. The refractory throat helps to control air flow and velocity, and the hot refractory helps to stabilize ignition by radiating heat back into the base of the flame. Adjustment of the air registers either initially or on a continuous basis with load swings helps to ensure that optimum air velocities are available for the combustion process. Register burners may be used with ambient or preheated air, oil atomizers, and/or gas burning equipment. Capacities from 10 to 200 million Btu/hr are common.

(2) **Low Excess Air Burners.** Low excess air (LEA) burners, as shown in figure 2-44, were developed to achieve lower excess air levels throughout the burner load range than is possible with register burners. A venturi section ensures uniform air flow at the burner outlet. An impeller is used to swirl a portion of the air into the atomized oil. The remainder of the air moves axially through the burner at a velocity designed to cause it to mix later with the fuel and impeller-swirled air. The advantage of the LEA burner is its ability to operate at low excess air levels, with subsequent improvements in efficiency. The main disadvantage is a long, narrow flame which is not well suited for many furnace configurations. Very accurate combustion controls are needed to take advantage of this burner's low excess air capability.

(3) **Package Burners.** Package burners include the forced draft fan and its air control damper, the oil and/or gas control valves, actuators, igniters, flame safety system, and combustion controls as a shop-assembled unit. Figure 2-45 illustrates an air atomizing oil- and gas-fired package burner. The cost and performance capability of package burners vary widely. Not all packages are suitable for every application. Every burner application requires careful consideration to ensure that the proper burner, controls and accessories are applied. Package burners should be capable of automatic start-up, shutdown, and modulating firing rate. Package burners are available for firing rates of several gallons to several hundred gallons per hour. Either register or low excess air type burners may be supplied as packages, and rotary, pressure, or fluid atomizers may be used.

2-22. OIL STORAGE AND HANDLING.

Above-ground and underground fuel storage tanks are available as illustrated in figures 2-45 and 2-46. These

tanks are provided with some or all of the following auxiliary equipment and connections: fill, vent, return, sludge pump-out, low suction, high suction, steam smothering, fire-fighting connections, gage connection, suction box, suction or tank heater, steam connection, level indicator, temperature indicator, access manholes, ladders, piping, and valves. The amount of storage capacity installed depends on the mission of the base, availability of dependable supply, and frequency of delivery. Storage tanks and oil-burning equipment must be installed in accordance with the NFPA 30 "Flammable and Combustible Liquids Code," and NFPA 31, "Standard for the Installation of Oil Burning Equipment."

a. Fuel Oil Preparation. No. 2 and No. 4 oil normally only require a pump set to transfer oil from storage to the burner. Paraffin base No. 4 oil may also require a small amount of heating. The use of day tanks and transfer pumps may be necessary if main storage tanks are located remotely from the plant. No. 5 and No. 6 oil require pumping and heating equipment to prepare and move the oil to the combustion equipment. Figure 2-47 illustrates a duplex pumping and heating set. A pressure regulatory valve is provided to return unneeded oil to the storage or day tank before it is heated. This avoids overheating of storage tanks in addition to maintaining the desired oil pressure. Insulation of oil, steam, and condensate lines is required, and electric or steam heat tracing of lines may be required in some applications.

b. Safety Equipment. The NFPA establishes requirements for safe boiler operation for boilers with 10,000 pounds of steam per hour and larger. These requirements are contained in NFPA 85A, "Standard for Prevention of Furnace Explosions in Fuel Oil- and Natural Gas-Fired Single Burner Boilers-Furnaces". Figures 2-48 and 2-49 show schematic arrangements of safety equipment for oil-fired water tube and fire tube boilers, respectively. Standards for oil-fired multiple burner boilers are found in NFPA 85D. For boilers rated less than 10,000 pounds of steam per hour, Underwriters Laboratories Inc., Underwriters Laboratories of Canada, or other nationally recognized organizations establish safety requirements and tests, and approve safety equipment.

2-23. GAS-FIRING EQUIPMENT.

Natural gas is an easy and clean fuel to burn and requires less equipment and maintenance than coal or oil systems. Its disadvantages include higher cost than coal, uncertain and limited availability, and a greater danger of explosion. Paragraphs 1-4c, 1-9, and 1-9a describe the potential for explosions and some of the necessary precautions. Early gas-firing equipment used gas velocity to aspirate air into the burner throat, where it was premixed with the gas

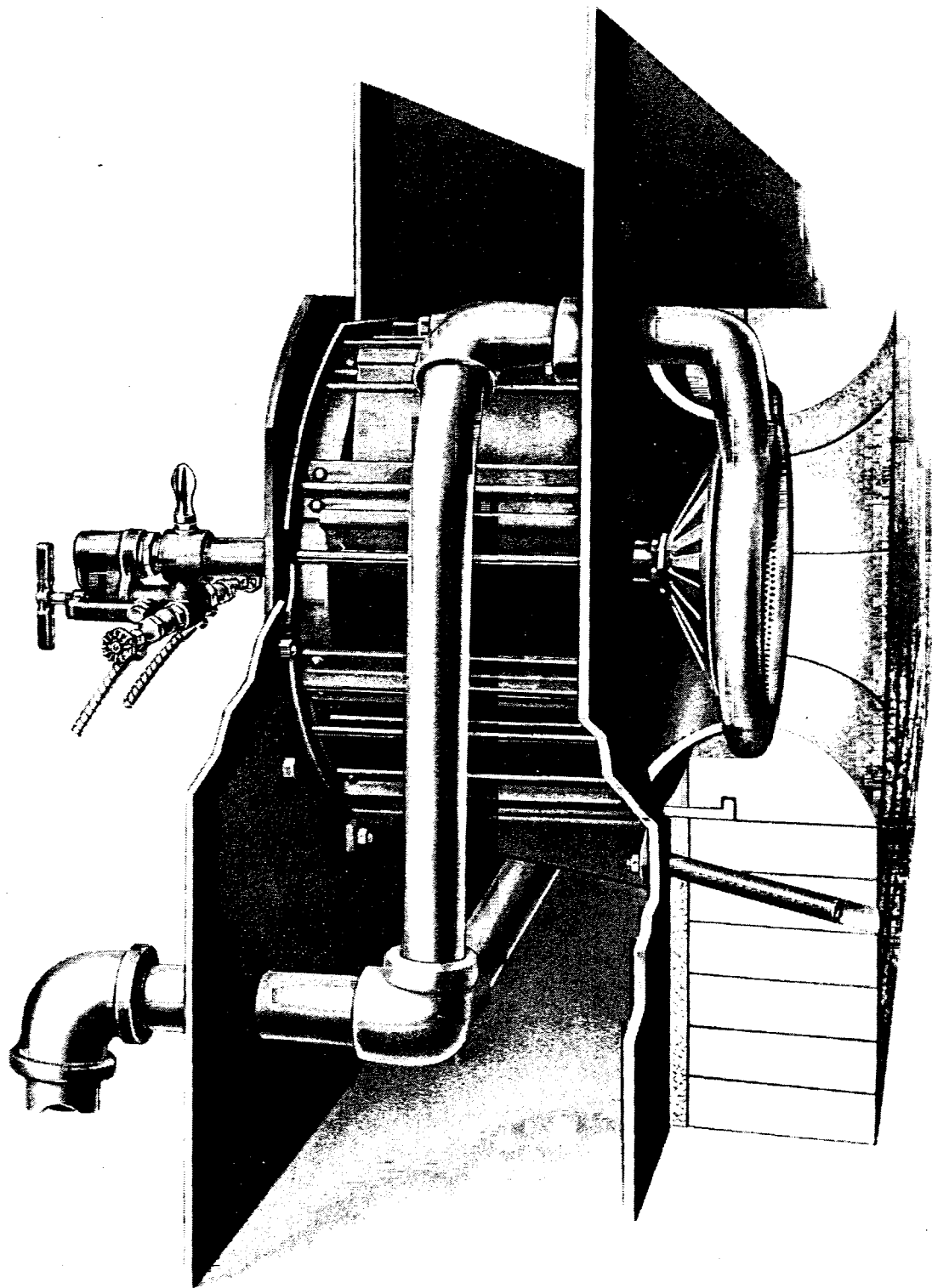


FIGURE 2-43. REGISTER BURNER

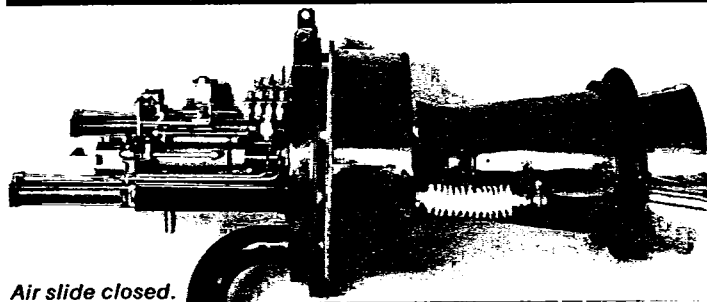
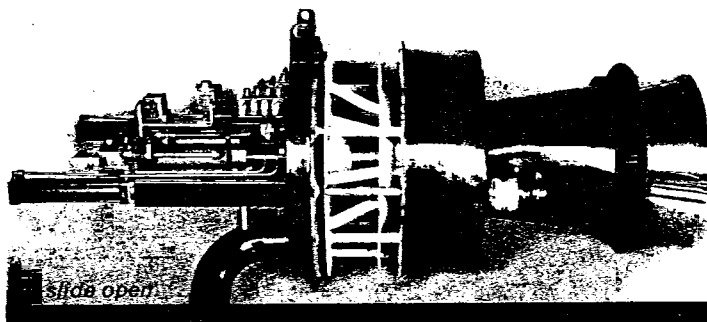
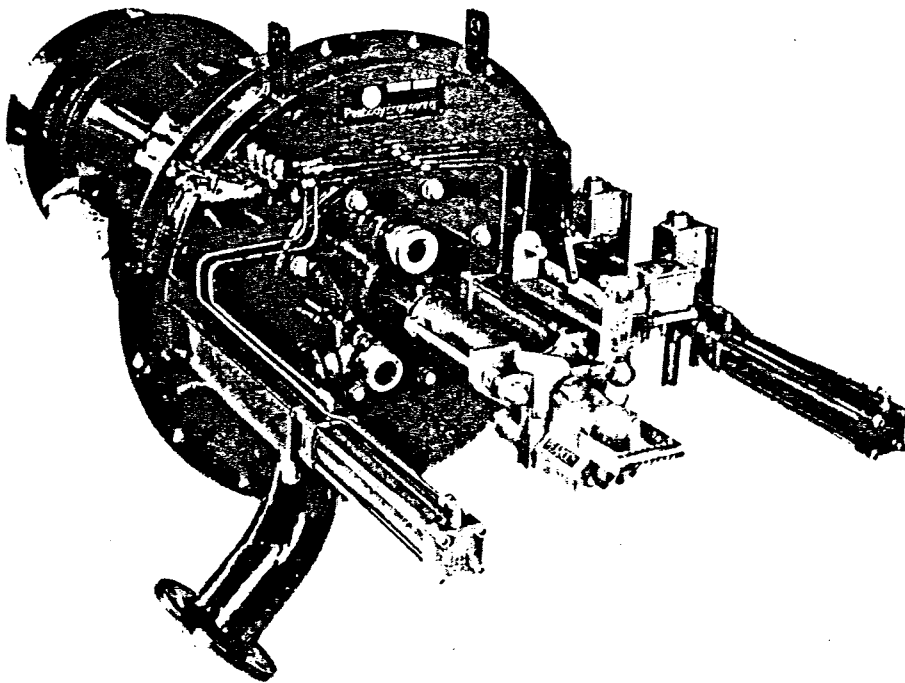
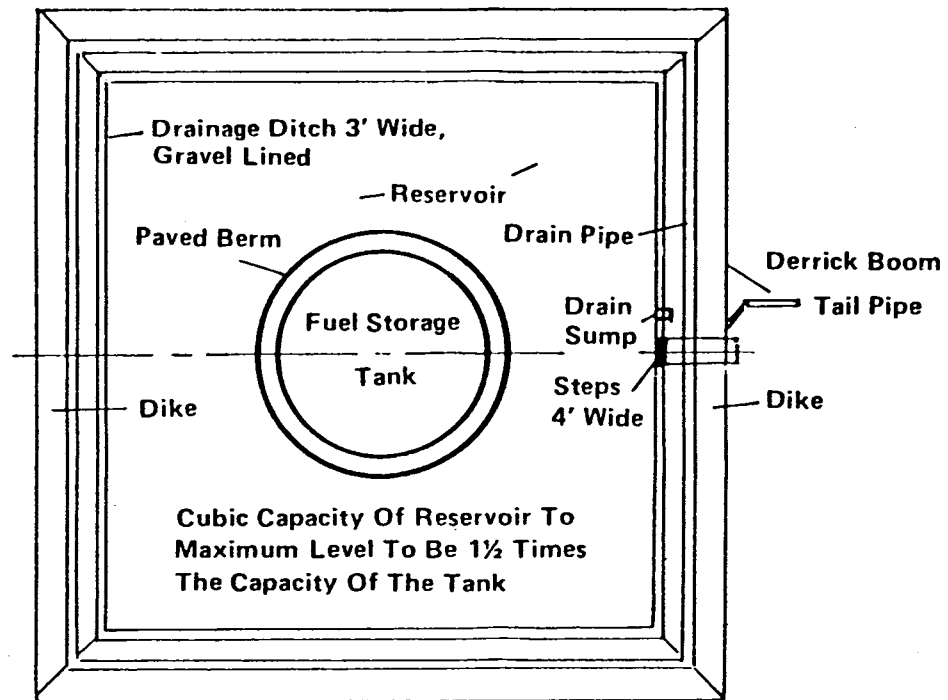
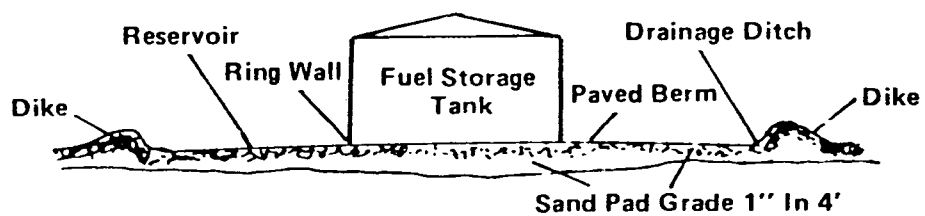


FIGURE 2-44. LOW EXCESS AIR BURNER



Plan View Of Tank Enclosure



Section Through Tank Enclosure

FIGURE 2-45. ARRANGEMENT OF ABOVE-GROUND FUEL OIL TANK

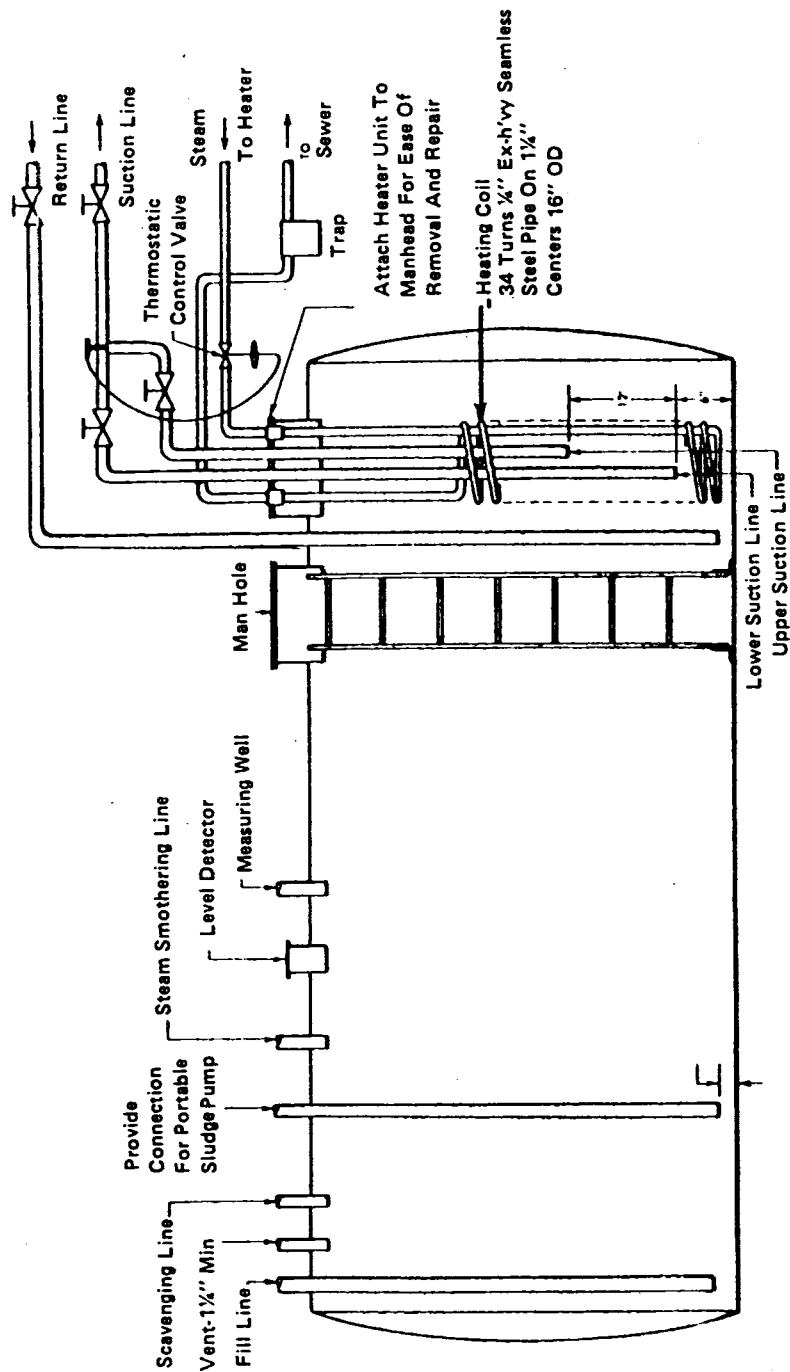


FIGURE 2-46. UNDERGROUND FUEL OIL STORAGE TANK

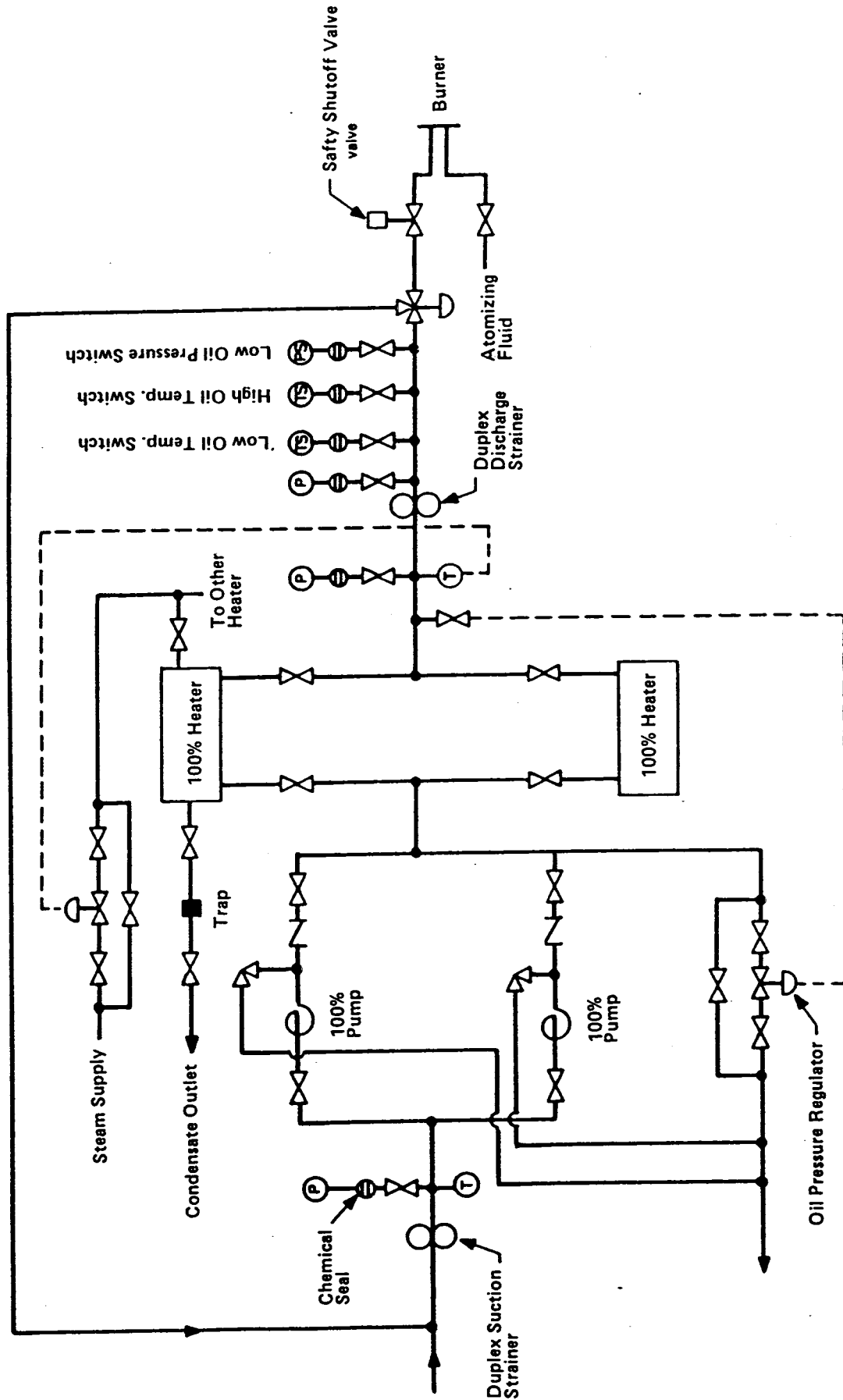
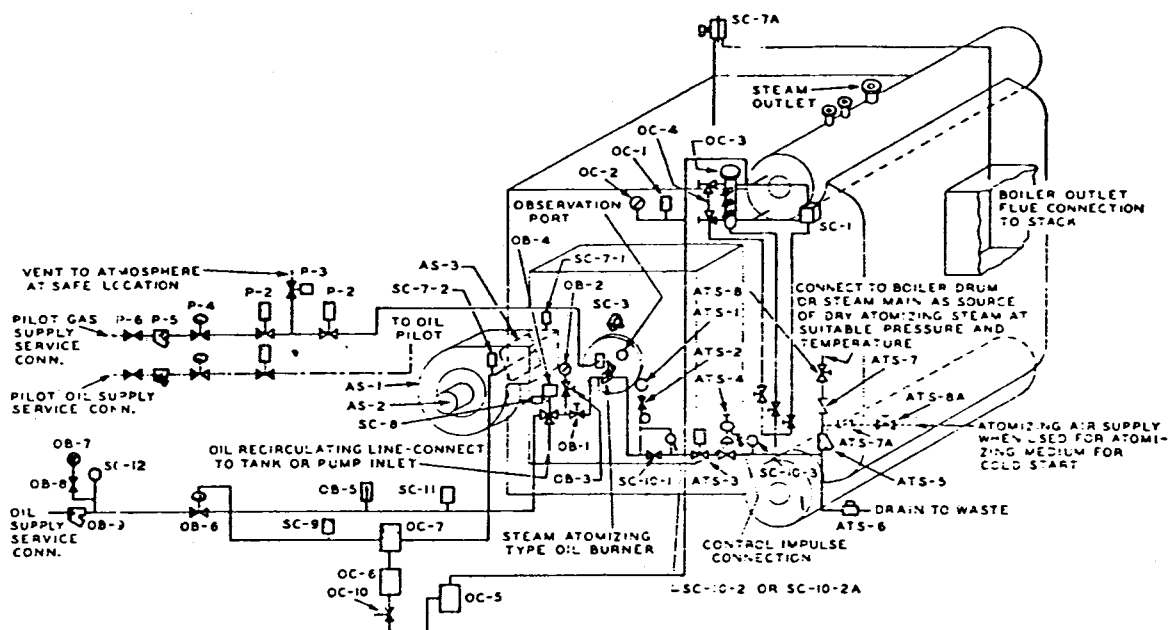


FIGURE 2-47. FUEL OIL PUMPING AND HEATING EQUIPMENT



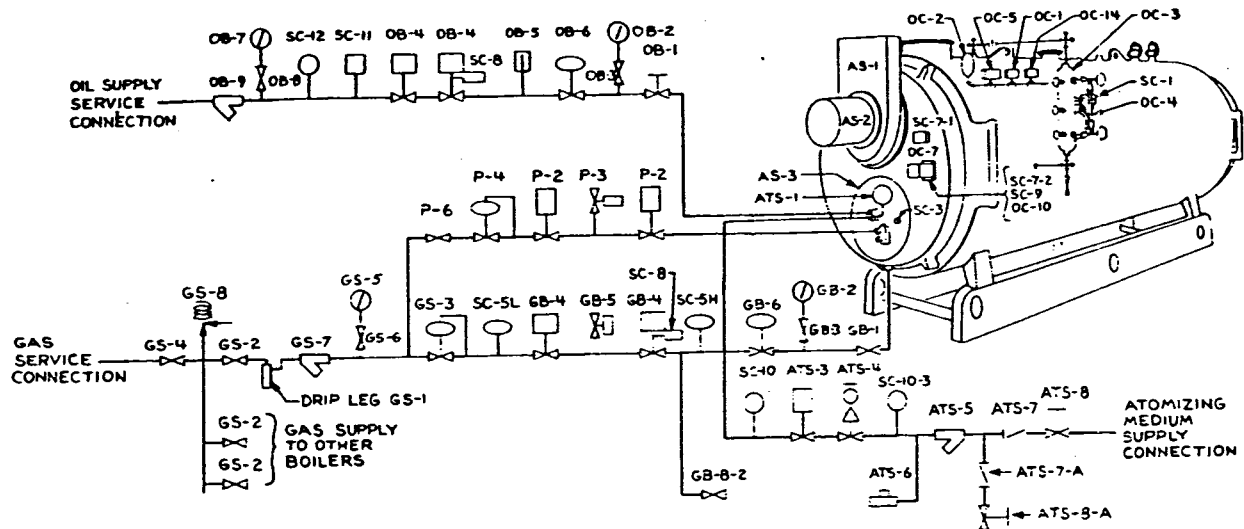
OIL FIRING ONLY
Typical Schematic Arrangement of Safety Equipment
Fuel Oil-Fired Watertube Boiler with One (1) Burner
Automatic (recycling) or Automatic (non-recycling) Controls

LEGEND

Atomizing Steam System:		
ATS-1	Burner atomizing steam pressure gage	P-4 Pressure regulating valve — optional depending on igniter pressure requirements.
ATS-2	Burner atomizing steam pressure gage cock	P-5 Strainer
ATS-3	Atomizing steam shut-off valve	P-6 Manual plug cock
ATS-4	Atomizing steam differential pressure control valve	
ATS-5	Atomizing steam supply strainer	Oil Burner System:
ATS-6	Atomizing steam supply trap	OB-1 Manual oil shutoff valve
ATS-7	Atomizing steam supply check valve	OB-2 Oil burner pressure gage
ATS-7A	Atomizing air supply check valve	OB-3 Oil burner pressure gage cock
ATS-E	Atomizing steam supply shut-off valve	OB-4 Safety shutoff and recirculating valve
ATS-EA	Atomizing air supply shut-off valve	OB-5 Oil temperature thermometer or gage (Note 4)
		OB-6 Oil control valve
		OB-7 Oil supply pressure gage
		OB-8 Oil supply pressure gage cock
		OB-9 Oil strainer
Air System:		
AS-1	Forced draft fan	
AS-2	Forced draft fan motor	
AS-3	Forced draft fan control damper at inlet or outlet	
Igniter (Pilot) System — Gas or Oil:		
P-2	Safety shutoff valves — auto. opening, spring closing (NC)	
P-3	Vent valve — auto. closing, spring opening (NO)	
		Safety Controls: (All switches in "hot" ungrounded lines. See 4662)
		SC-1 Low water cut out integral with column or separate from water column
		SC-3 Flame scanner
		SC-7-1 Windbox pressure switch (Note 2)
		SC-7-2 Fan damper position switch (Note 2)
		SC-7A Purge airflow switch (Note 2)
		SC-8 Closed position interlock on OB-4
		SC-9 Light-off position interlock
		SC-10-1 Atomizing steam flow interlock orifice
		SC-10-2 Atomizing steam flow interlock differential pressure switch
		SC-10-2A Atomizing steam pressure interlock switch
		SC-10-3 Atomizing steam supply pressure interlock switch
		SC-11 Low oil temperature interlock (Note 4)
		SC-12 Low oil supply pressure interlock
		Operating Controls & Instruments:
		OC-1 High steam pressure switch (Note 1)
		OC-2 Steam drum pressure gage
		OC-3 Water column with high & low level alarms
		OC-4 Water gage and valves
		OC-5 Steam pressure controller
		OC-6 Manual auto. selector station
		OC-7 Combustion control drive unit or units
		OC-10 Modulating control low fire start positioner

- NOTES:**
1. With automatic (non-recycling) control, an overpressure shutdown requires manual restart.
 2. Purge airflow may be proved by providing either SC-7-1 and SC-7-2 (and similar devices for other dampers which are in series) or SC-7A.
 3. Atomizing steam interlock may be accomplished by providing either SC-10-1 and SC-10-2 or SC-10-2A and SC-10-3.
 4. Temperature interlock and thermometer omitted for light oils which do not require heating.
 5. Arrangement shown is applicable to straight mechanical pressure atomizing oil burners by omitting atomizing steam system.

**FIGURE 2-48. SAFETY EQUIPMENT OIL-FIRED
WATER TUBE BOILER**



ALTERNATE GAS OR OIL FIRING
Typical Schematic Arrangement of Safety Equipment
Gas- and Oil-Fired (alternately) Firetube Boiler With One (1) Burner
Automatic Recycling Controls

LEGEND

Atomizing Medium System (See Note 5): ATS-1 Atomizing pressure gage ATS-3 Atomizing medium shut-off valve ATS-4 Atomizing medium differential pressure control (if req'd.) ATS-5 Atomizing medium supply strainer ATS-6 Atomizing steam supply trap ATS-7 Atomizing steam supply check valve ATS-7A Atomizing air supply check valve ATS-8 Atomizing steam supply shut-off valve ATS-8A Atomizing air supply shut-off valve		Gas Supply System: GS-1 Drip leg GS-2 Manual plug cock GS-3 Gas supply pressure reducing valve GS-4 Manual gas supply shut-off valve GS-5 Gas supply pressure gage GS-6 Gas supply pressure gage cock GS-7 Gas cleaner GS-8 Relief valve		Gas Burner System: GB-1 Manual plug cock GB-2 Gas burner pressure gage GB-3 Gas burner pressure gage cock GB-4 Safety shut-off valves, auto, draining, spring closing (NC) GB-5 Vent valve, auto. closing, spring opening (NO) GB-6 Gas fuel control valve GB-8-2 Leakage test connection downstream safety S.O. valves		SC-3 Flame scanner SC-5H Gas supply high pressure switch SC-5L Gas supply low pressure switch SC-7-1 Windbox pressure switch (See Note 2) SC-7-2 Fan damper position switch (See Note 2) SC-8 Closed position interlock on GB-4 (overtravel) SC-9 Light-off position interlock SC-10 Atomizing medium pressure interlock switch SC-10-3 Atomizing medium supply pressure interlock switch SC-11 Low oil temp. interlock (See Note 4) SC-12 Low oil supply pressure interlock	
Air System: AS-1 Forced draft fan AS-2 Forced draft fan motor AS-3 Forced draft fan control damper at inlet or outlet		Oil Burner System: OB-1 Manual oil shut-off valve OB-2 Oil burner pressure gage OB-3 Oil burner pressure gage cock OB-4 Safety shut (with recirculation optional) OB-5 Oil temperature gage (See Note 4) OB-6 Oil control valve OB-7 Oil supply pressure gage OB-8 Oil supply pressure gage cock OB-9 Oil strainer		Operation Controls & Instruments: OC-1 High steam pressure switch (See Note 3) OC-2 Steam drum pressure gage OC-3 Water column (may be equipped with low water cut-out and feed-water pump control) OC-4 Water gage and valves OC-5 Steam pressure controller OC-7 Combustion control drive unit OC-10 Modulating control — low fire start positioner OC-14 Excessive steam pressure switch (See Notes 1 & 3)		Igniter (Pilot) System: P-2 Safety shut-off valve, auto. opening, spring closing (NC) (See Note 6) P-3 Vent valve, auto. closing, spring opening (NO) (See Note 6)	
Safety Controls (All Switches in Hot Un-grounded Lines): SC-1 low water cut-out (integral with or separate from water column)		Gas pressure regulating valve optional, depending on ignitor pressure requirements P-6 Manual plug cock					

- NOTES:**
1. Actuation of this switch normally requires manual reset.
 2. Purge air flow may be proven by providing SC-7-1 and/or SC-7-2.
 3. For hot water boilers, switches OC-1, OC-5 and OC-14 would be temperature sensing device.
 4. Temperature interlock and thermometer omitted for light oils which do not require heating.
 5. Arrangement shown is applicable to straight mechanical pressure atomizing or burners by omitting atomizing medium system.
 6. For pilots of less than 400,000 BTU/HR the vent valve (P-3) may be eliminated and only one safety shut-off valve (P-2) may be required.

FIGURE 2-49. SAFETY EQUIPMENT OIL- OR GAS-FIRED FIRE TUBE BOILER

before burning. Premix burners are now used for igniter service. The advent of forced draft fans and the need for increased burner capacity brought about the development of nozzle-mix gas burners. Nozzle-mix burners are capable of handling gas over a wide range of pressures depending on the design. Types of nozzle-mix burners include ring, gun, and multiple spud.

Figure 2-43 illustrates a register burner equipped with gas spuds and an oil atomizer. Figure 2-44 illustrates a low excess air burner equipped with a gas ring. NFPA 85A, "Standard for Prevention of Furnace Explosions in Fuel Oil- and Natural Gas-Fired Single Burner Boilers-Furnaces," establishes requirements for safe operation of gas-fired boilers. Figures 2-49 and 2-50 show schematic arrangements of safety equipment for gas-fired fire tube and water tube boilers. "Standards for Natural Gas-Fired

Multiple Burner Boilers" are found in NFPA 85B. For boilers rated less than 10,000 pounds of steam per hour, standards are set by Underwriters Laboratories Inc., Underwriters Laboratories of Canada, and other nationally recognized organizations.

2-24. LIQUEFIED PETROLEUM GAS.

Liquefied petroleum gas (LPG) is used for igniter service and occasionally as a standby fuel for natural gas- or oil-fired installations. LPG is a combination of propane and butane maintained in a liquid state through storage under pressure. NFPA Standards 58 and 54, Part 2 establish requirements for the storage and handling of LPG. For further information on LPG, refer to the Air Force Manual, No. 85-12.

SECTION IV. CONTROLS AND INSTRUMENTATION

Controls and instrumentation are an integral and essential part of all central boiler plants. They serve to assure safe, economic and reliable operation of the equipment. They range from the simplest of manual devices to completely automated, microprocessor-based systems for control of boilers, turbines, and even end-users of energy. The subjects of controls and instrumentation are so intimately related that they are difficult to separate, and are discussed in parallel in the following chapter. Only those systems and items which are commonly used in central boiler plants are discussed.

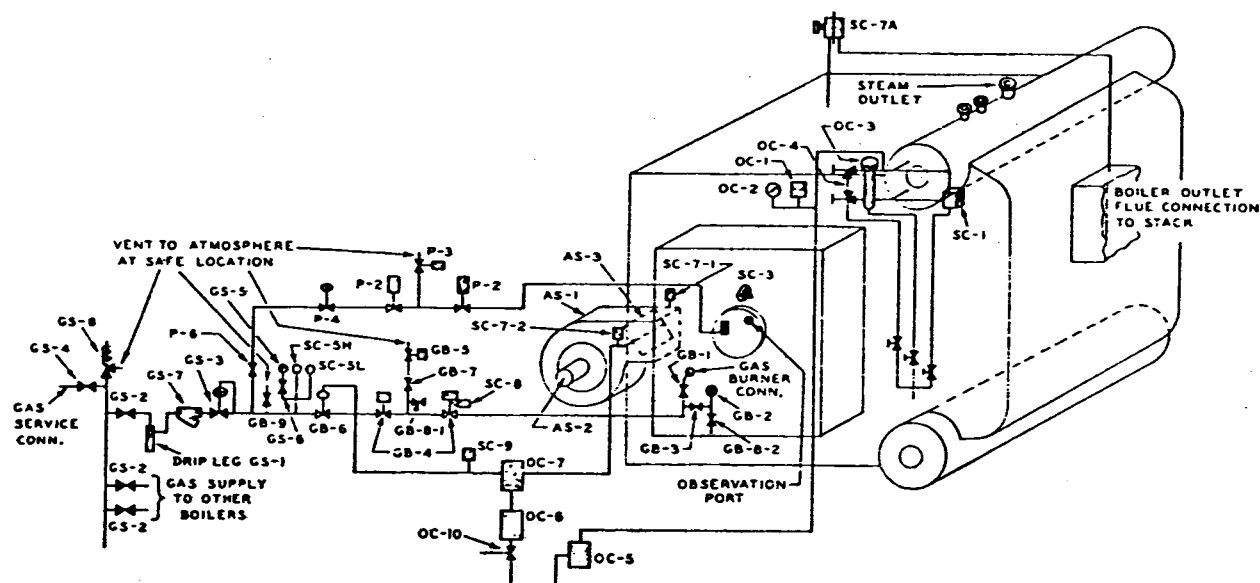
2-25. FEEDWATER-DRUM LEVEL CONTROLS.

The importance of an adequate, properly controlled supply of feedwater to a boiler cannot be overemphasized. Boiler feedwater pumps and injectors (paragraph 2-38), low water fuel cutoffs (paragraph 2-27), and feedwater heaters (paragraph 2-37) are all part of an effective feedwater system. Steam boilers also require drum level controls to maintain the water level within limits established by the manufacturer. Operating with water levels that are too high may cause carryover of water from the drum, while operating with levels that are too low can result in boiler tube failures due to insufficient cooling. Feedwater regulators are used to adjust the feedwater flow rate and maintain proper levels. Five types of feedwater regulators are commonly used: positive displacement, thermohydraulic, thermostatic, pneumatic level transmitter/controller, and electronic level transmitter/controller. Each is described below.

a. Positive Displacement. The positive-displacement type

feedwater regulator (figure 2-51) is connected to the boiler drum or water column so that the average water level in the chamber is in line with that of the drum. The rise and fall of the float with the water level actuates a balanced feed valve through a suitable system of levers, and reduces or increases the flow of water to the boiler. The entire mechanism is in the pressure space and there are no stuffing boxes to leak or bind. The float is initially charged with a small amount of alcohol, which vaporizes and pressurizes in the float to counteract the boiler pressure exerted on the outside of the float. The valve and linkage are designed to give a gradual and continuous change in water flow between the high and low limits. This type of control will maintain a different water level for each steam flow produced by the boiler.

b. Thermohydraulic. Operation of the thermohydraulic or vapor-generator type of feedwater regulator (figure 2-52) depends upon the principle that steam occupies a greater volume than the water from which it was formed. The equipment consists of a generator, a diaphragm-operated valve, and the necessary connecting pipe and tubing. The central tube of the generator is connected to the boiler drum or water column, with the tube inclined so that the normal drum water level is slightly above the center of the generator. The generator, tubing and diaphragm chamber are filled with hot water. In operation, heat from steam in the upper portion of the inner tube raises the temperature of the water surrounding that portion of the tube and converts part of it to steam. This increases the pressure in the generator, forcing part of the water out of the generator until the water level is the same in both the inner and outer tubes. The water which is



NATURAL GAS FIRING ONLY
Typical Schematic Arrangement of Safety Equipment
Natural Gas-Fired Watertube Boiler with One (1) Burner
Automatic (recycling) or Automatic (nonrecycling) Controls

LEGEND

Gas Supply System:

- GS-1 Drip leg
- GS-2 Manual plug cock
- GS-3 Gas supply pressure reducing valve
- GS-4 Manual gas supply shut-off valve
- GS-5 Gas supply pressure gage
- GS-6 Gas supply pressure gage cock
- GS-7 Gas cleaner
- GS-8 Relief valve

Air System:

- AS-1 Forced draft fan
- AS-2 Forced draft fan motor
- AS-3 Forced draft fan control damper at inlet or outlet

Igniter (Pilot) System:

- P-2 Safety shut-off valves, auto. opening, spring closing (NC)
- P-3 Vent valve, auto. closing, spring opening (NO)
- P-4 Gas pressure regulating valve optional depending on igniter pressure requirements
- P-6 Manual plug cock

Gas Burner System:

- GB-1 Manual plug cock
- GB-2 Gas burner pressure gage
- GB-3 Gas burner pressure gage cock
- GB-4 Safety shut-off valves, auto. opening, spring closing (NC)
- GB-5 Vent valve, auto. closing, spring opening (NO)
- GB-6 Gas fuel control valve
- GB-7 Vent line manual plug cock (locked or sealed in open position)
- GB-8-1 Leakage test conn. upstream safety S.O. valve
- GB-8-2 Leakage test conn. downstream safety S.O. valve
- GB-9 Manual plug cock for venting high pressure from supply when required

Safety Controls: (All switches in "hot" ungrounded lines. See 4662)

- SC-1 Low water cut out integral with column or separate from water column
- SC-3 Flame scanner
- SC-5H Gas supply high pressure switch
- SC-5L Gas supply low pressure switch

- SC-7-1 Windbox pressure switch (note 2)
- SC-7-2 Fan damper position switch (note 2)
- SC-7A Purge A.F. switch (note 2)
- SC-8 Closed position interlock on GB-4
- SC-9 Light-off position interlock

Operating Controls & Instruments:

- OC-1 High steam pressure switch (note 1)
- OC-2 Steam drum pressure gage
- OC-3 Water column with high & low level alarms
- OC-4 Water gage and valves
- OC-5 Steam pressure controller
- OC-6 Manual auto. selector station
- OC-7 Combustion control drive unit or units
- OC-10 Modulating control low fire start positioner

NOTES: 1. With automatic (non-recycling) control an overpressure shutdown requires manual restart.

2. Purge airflow may be proved by providing either SC-7-1 and SC-7-2 (and similar devices for other dampers which are in series) or SC-7A.

FIGURE 2-50. SAFETY EQUIPMENT
GAS-FIRED WATER TUBE BOILER

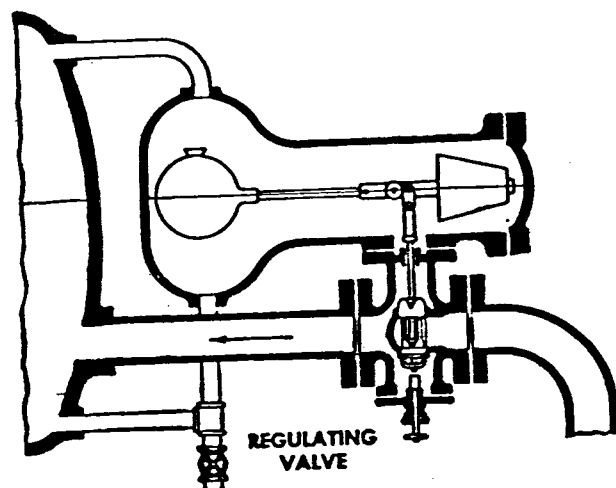


FIGURE 2-51. POSITIVE DISPLACEMENT
FEEDWATER REGULATOR

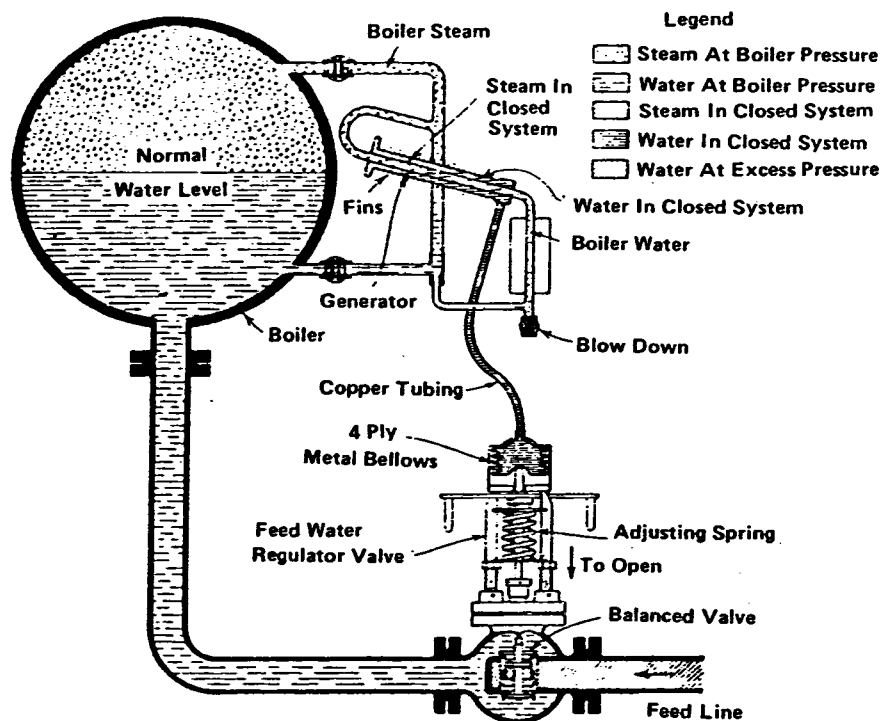


FIGURE 2-52. VAPOR-GENERATOR/THERMOHYDRAULIC FEEDWATER REGULATOR

forced out of the generator moves the diaphragm and opens the valve. When the water level in the boiler rises, some of the steam in the generator condenses and lowers the pressure. The spring on the valve forces water into the generator, closing the valve in the process. Fins are installed on the generator to radiate away some of the heat absorbed, thus preventing excessive pressures in the generator circuit and increasing the speed of response of the regulator. This type of regulator establishes a relation between water level in the drum and the valve opening. Therefore, for each stream flow rate, a slightly different water level will be maintained.

c. **Thermostatic.** Operation of the metal thermostat or expansion type of regulator (figure 2-53) depends upon the expansion and contraction of an inclined metal tube. The expansion tube is mounted on a steel frame in such a way that it is under constant tension. It is connected to the steam and water spaces of the boiler so that it contains only steam when the water is at its lowest level. The tube is then expanded to its maximum length. As the water level in the boiler rises, the water also rises in the tube, causing it to cool and contract. The tube is connected to a balanced valve in the feedwater line by a system of levers which move the valve as the tube length changes. The feedwater valve is at its maximum opening when the water level is low and the tube is filled with steam, and closes as the water level rises and the tube shortens. Note that all of the above regulators increase the flow of water as the level drops.

d. **Pneumatic Transmitter/Controller.** As boiler firing rates increased with the development of the modern water-cooled furnaces, the water storage capacity decreased and feedwater control became more difficult. A steam drum in a modern boiler can be emptied of water in minutes if the supply is shut off. Changes in steam pressure result in expansion or swelling of the steam/water mixture and false water-level indications. The mechanical controls discussed previously have limited capabilities and slow response times, and pneumatic controls were developed to provide more accurate drum level control. Basic to all pneumatic systems are a drum-level transmitter to sense level, a manual/automatic station to allow manual control during start-up, and a controller to determine the adjustment required to the feedwater valve. Single-, two- and three-element feedwater controls are available.

(1) **Single Element.** Single-element controls use a drum-level transmitter with a manual/automatic station and controller to send a signal to position the feedwater control valve. The controller can be adjusted to provide responsive and accurate control. Single element control is adequate for systems with gradual load changes.

(2) **Two Element.** In two-element controls, both drum level and steam flow levels are measured and used to control the feedwater (reference figure 2-54). Because steam flow

is measured, this control system can sense and respond to load changes before they result in drum level changes. The system can thus compensate for swelling and shrinking in the boiler and drum which occur as the pressure changes during load swings. Two-element control is recommended for systems with frequent and large load changes.

(3) **Three Element.** Three-element controls sense feedwater flow in addition to drum level and steam flow. Three-element systems can compensate for changes in feedwater flow that may occur due to feedwater pressure or temperature change or feedwater valve inaccuracies. This level of control is not normally necessary except for very large boilers used in systems with large load changes, or in boilers producing superheated steam for use in a turbine.

e. **Electronic Transmitter/Controller.** One-, two-, and three-element feedwater control systems are also available utilizing electronic transmitters, manual/automatic stations, and controllers. Electric or pneumatic actuators can be used as final control drives for the feedwater control valve. An electro-pneumatic transducer is required to convert the electric signal into a pneumatic signal when pneumatic components.

2-26. COMBUSTION CONTROLS.

Combustion controls adjust fuel and air flows to satisfy boiler demand. Steam pressure, which changes with changes in demand, serves as the input signal by which the boiler firing rate is controlled. In hot water boilers, the water temperature leaving the boiler is used as the input signal. A combustion control system must maintain an efficient fuel/air ratio. For boilers equipped with induced draft fans or tall stacks, the combustion controls must also adjust fan inlet dampers or boiler outlet dampers to control furnace draft. A combustion control system, no matter how sophisticated, cannot do a better job of controlling a boiler than an operator. However, a combustion control system will operate continuously to make the necessary adjustments, while an operator has other responsibilities that prevent this kind of attention. Combustion controls systems are comprised of the following general types of components:

- | | |
|--------------------|------------------|
| — Sensing elements | — Actuators |
| — Transmitters | — Control drives |
| — Controllers | — Control valves |
| — Indicators | — Dampers |

These components may be combined in an endless variety of arrangements to provide almost any degree of sophistication required.

a. **Control Concepts.** Open-loop and closed-loop control are both used in the boiler plant. Open-loop control (also called "feed-forward") takes an input-demand signal and generates a single output in response to the demand. The

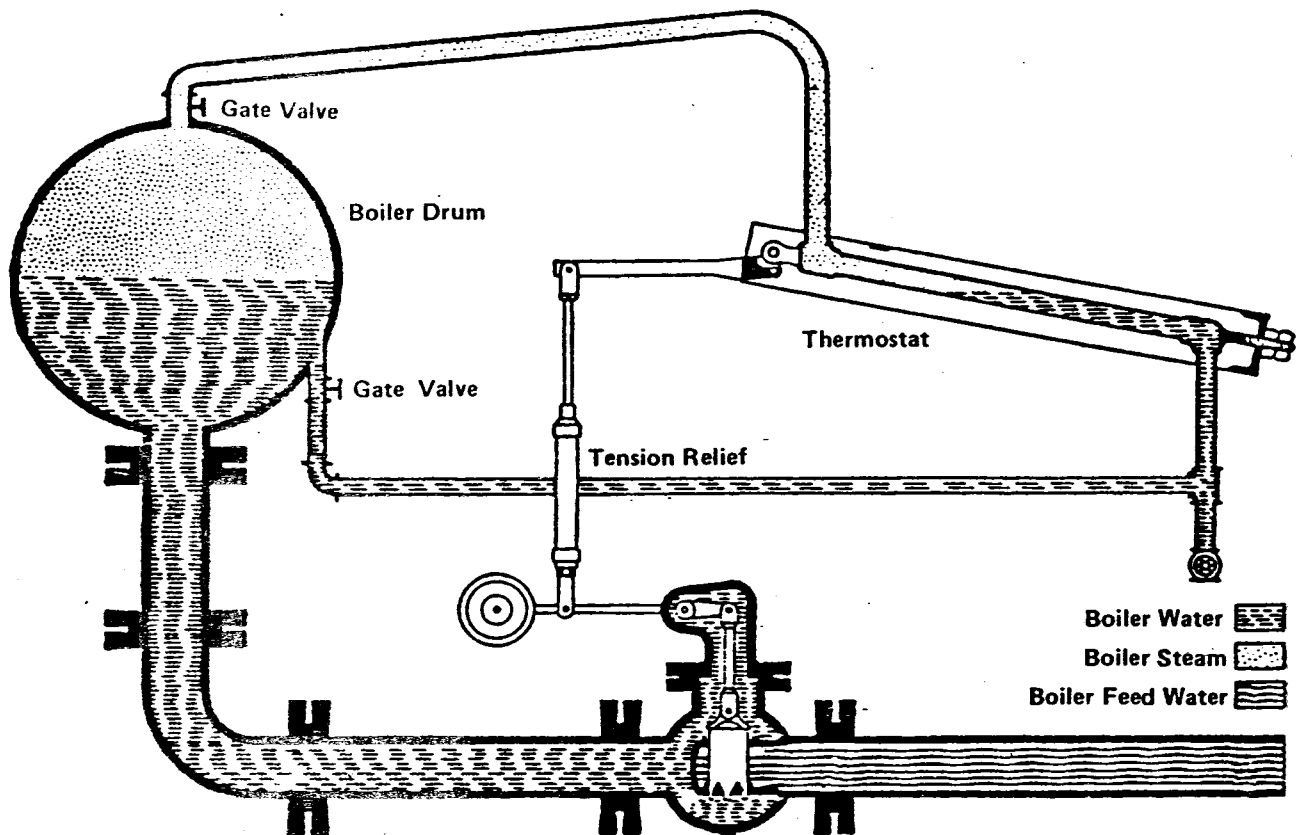


FIGURE 2-53. THERMOSTATIC/METAL EXPANSION
FEEDWATER REGULATOR

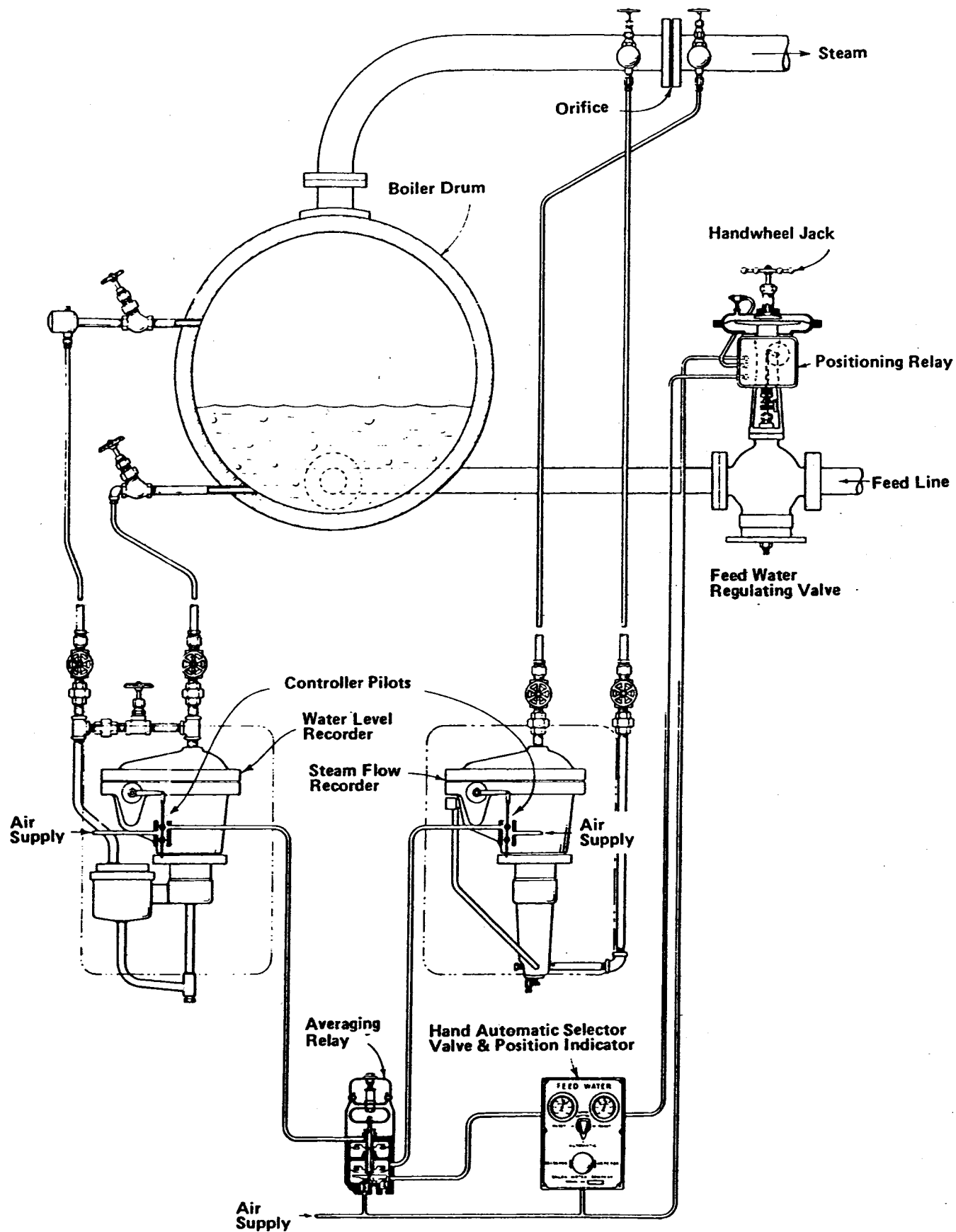


FIGURE 2-54. TWO ELEMENT FEEDWATER CONTROLS

result of the control action is not considered. Closed-loop (or "feedback") control monitors a system variable and automatically generates an output to adjust the system. If the system remains out of balance, the control will continue to change its output until the desired result is obtained. A simple pneumatic actuator on a valve is an example of open-loop control (reference figure 2-55). The actuator receives a signal and generates an output, the movement of its shaft. This same pneumatic actuator could be converted to closed-loop control by equipping it with a positioner (reference figure 2-56). The actuator receives a signal and generates an output to move the shaft. The shaft position is measured as feedback. If the shaft is not in the desired position, the output from the positioner is automatically readjusted, and the shaft is moved again until it is in the correct position. A basic advantage of closed-loop control is that it provides more accuracy of adjustment due to its ability to overcome hysteresis losses. Hysteresis losses are caused by friction in linkages, valves, actuators, and other mechanical items. The effect of hysteresis is to cause a valve or mechanism to stop at a slightly different adjustment each time. A typical open-loop control may be able to control position within plus or minus 5% of a desired setting, whereas a closed-loop control can typically control to approximately plus or minus 1%. Closed-loop control is available as one-, two-, or three-mode control using proportional, integral, or derivative responses. These different responses are discussed below.

(1) **Proportional.** Proportional control (also called gain control) is the simplest form of closed-loop control. In proportional control, the difference between a setpoint and a system variable is measured, and corrective action is taken by adjusting the control output. A proportional steam pressure control system is illustrated in figure 2-57. Steam pressure setpoint and actual steam pressure are compared, and an output is generated in proportion to the difference. Figure 2-58 illustrates proportional control. For a proportional gain setting of 5, the fuel valve is opened 5% for each 1% drop in steam pressure. Proportional gain, or simply gain, is defined as "the control output change, in percent, divided by the system variable change, in percent."

$$\text{Gain} = \frac{\text{Change in Control Output, \%}}{\text{Change in System Variable, \%}}$$

Proportional band is the inverse of gain, expressed in percent.

$$\text{Proportional} = \frac{1}{\text{Gain}} \times 100 = \frac{\text{Change in System Variable, \%}}{\text{Change in Control Output, \%}} \times 100$$

Thus, a gain of 5 is equivalent to a proportional band of 20. Figure 2-59 illustrates the response of a steam pressure

control system to a change in steam flow. Note that offset or deadband is the difference between setpoint and steam pressure. The following observations should be noted about proportional control:

(a) Proportional control operates and establishes steady-state positions because a difference exists between the setpoint and the system variable. In the example shown in figure 2-58, only at the 50% fuel valve position would steam pressure exactly match the setpoint. At all other fuel valve positions, a difference of up to 10 psi from setpoint would be required to maintain the fuel valve position which would satisfy a steam flow demand.

(b) The larger the gain (or the smaller the proportional band) of a control, the greater the response of the control to changes in the system variable, and the smaller the deadband.

(c) The smaller the gain (or the larger the proportional band), the smaller the response to changes in the system variable, and the larger the deadband.

(d) A large gain may not be stable. A fuel valve cycling between full open and full closed is an example of unstable operation.

(2) **Integral.** Integral (also called reset) control was developed to improve the accuracy of proportional control. Integral action works to eliminate the deadband which is inherent in proportional control. Integral control adjusts the control output in steps based upon the offset and the time the offset has existed. Adjustment continues until the setpoint and the system variable are the same or until maximum or minimum output is reached. Figure 2-60 illustrates proportional plus integral control response to a change in steam flow. Proportional plus integral control is also called two-mode control. Reducing the integral time increases the integral control response, while increasing the integral time reduces the control response.

(3) **Derivative.** Derivative is a mathematical term that considers the rate of change. In some systems, derivative (or rate) response can improve the speed and accuracy of the control by anticipating a trend before an actual change occurs. Proportional plus integral plus derivative control is called three-mode control; it is rarely used in a steam heating plant but can be very effective in a hot water plant by recognizing change in direction of a system variable. For example, when boiler outlet water temperature starts to fall after having been rising, the fuel valve should be opened to supply heat to satisfy the new demand for hot water, even though the setpoint may not have been reached yet. Reducing the derivative time increases the derivative control response, while increasing the derivative time decreases the response. To much derivative control can dampen other control responses.

b. Pneumatic Control Basics. A basic pneumatic controller is shown in figure 2-61. The controller consists of the five

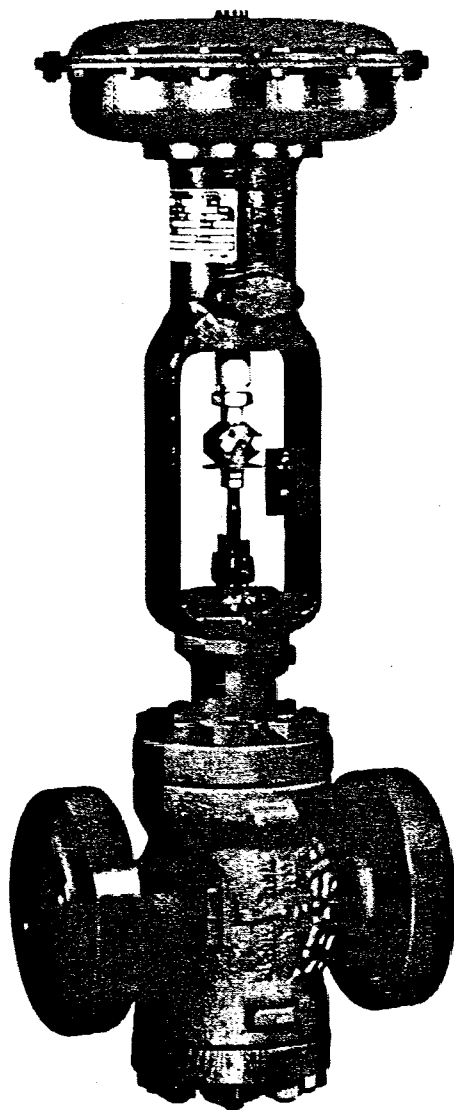


FIGURE 2-55. CONTROL VALVE WITH
PNEUMATIC ACTUATOR

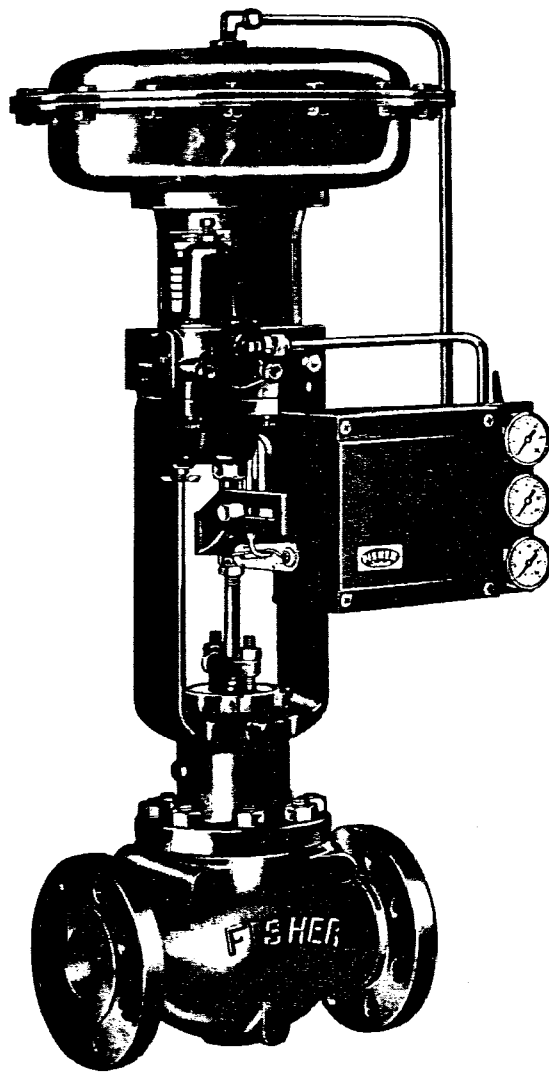


FIGURE 2-56. CONTROL VALVE WITH PNEUMATIC ACTUATOR AND POSITIONER

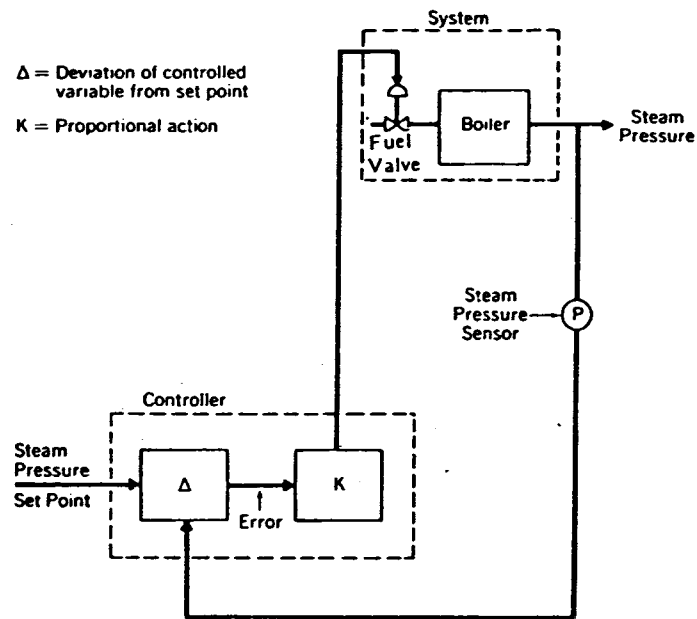


FIGURE 2-57. STEAM PRESSURE CONTROL SYSTEM

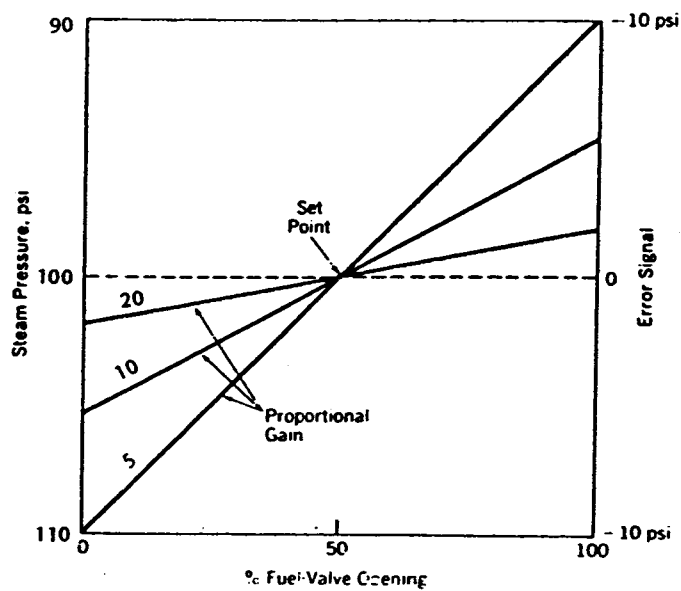


FIGURE 2-58. PROPORTIONAL CONTROL

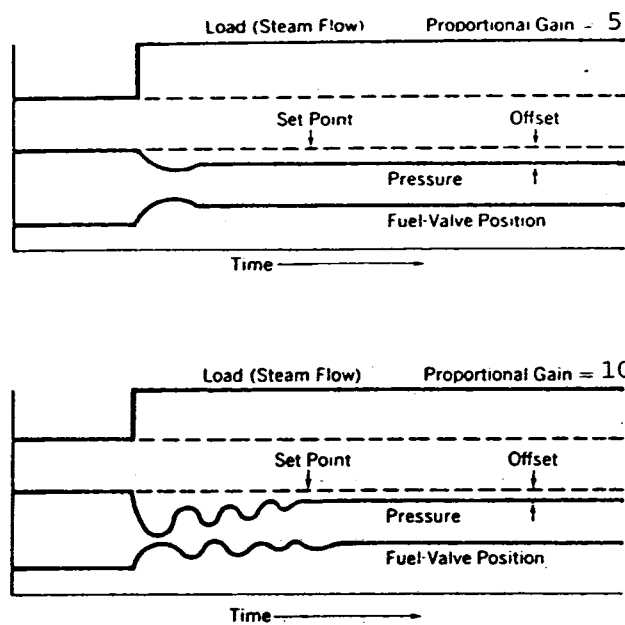


FIGURE 2-59. PROPORTIONAL RESPONSE

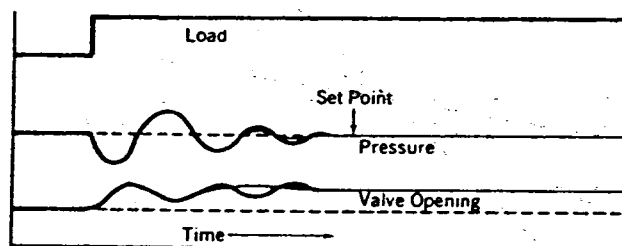


FIGURE 2-60. PROPORTIONAL PLUS INTEGRAL RESPONSE

basic components listed below.

- Measuring element.
- Flapper
- Nozzle or venting orifice
- Restrictive or input orifice
- Chamber between the orifices

The flapper is situated so that it can shut off or throttle the flow of air out of the nozzle orifice, and is moved by the sensing element in response to a change in the controlled variable. The flapper and venting orifice are often considered as one unit, called a vent valve. Instrument quality air is supplied to the controller through the input orifice and is vented to the atmosphere through the venting orifice, as long as the flapper is positioned away from this orifice. The venting orifice is larger than the input orifice; therefore, if the flapper restricts the flow of air, air pressure in the chamber and control air pressure to the final control drive positioner both increase. The mount of clearance between the flapper and the nozzle controls the air pressure fed to the control drive. The measuring element controls the flapper-nozzle clearance as dictated by the pressure, temperature, flow level, etc., being controlled. This fundamental controller has rather limited capability and, if used, must be situated close to the device it controls. It

must actuate a control requiring only a small volume of air, and it must control a process that requires only a limited control range. It is a one-mode controller, with the proportional band determined by the position of the pivot point, venting orifice, and measuring element. Two-mode and three-mode controllers are developed by using additional measuring elements, flappers, orifices, chambers, adjusting mechanisms, and springs. The basic controller is flexible if equipped with a power or volume booster relay. A typical two-diaphragm booster relay is shown in figure 2-62. The ratio of the two-diaphragm areas may be varied to suit the desired input-output ratio. A relay with a three-to-one diaphragm ratio will give a 3-psi change in the control air output signal for each 1-psi change in chamber "A". Depending upon the ratio of the diaphragm areas, this type of relay may be used to increase either the volume of air or the control air pressure at the drive. Control air from the controller chamber, acting on the diaphragm in chamber A causes diaphragms "A" and "B" to move downward, thus opening valve 2 which admits air from chamber "D" to chamber "C." When the force exerted by the control air in chamber "C" equals the force in chamber "A", the downward movement of the diaphragm assembly ceases and the control air output pressure to the control device will remain constant. When the pressure in chamber "A" decreases, the diaphragm assembly will move upward; valve 2 will close and valve 1 will open, thus venting air out of chamber "C" to the atmosphere through chamber "B". This causes a decrease of control air pressure to the control device.

c. Controls for Stoker-Fired Boilers. Combustion controls for stoker-fired boilers must have the ability to adjust the fuel/air ratio to compensate for changes in coal heating values, moisture, bed thickness, forced draft fan performance, and ambient air changes. Spreader stokers, which burn a portion of the coal in suspension, react differently than underfeed, traveling, chain, and vibrating stokers. Spreader stokers respond best to a change in fuel feed rate, while grate-burning stokers respond well to changes in air flow rates. Two types of control, parallel positioning control and series/parallel control, are commonly used with stokers.

(1) **Parallel Positioning Control.** Figure 2-63 illustrates a parallel positioning control system. A deviation of steam pressure from setpoint results in the master controller signaling the fuel actuator and the combustion and overfire air actuators to reposition themselves to a higher firing rate. Two fuel/air ratio control stations are provided to allow the operator to adjust and trim the combustion and overfire air supply. A furnace pressure controller monitors the furnace pressure and adjusts the ID fan inlet damper to maintain a slightly negative pressure in the furnace. Manual/automatic stations are provided to allow manual control.

(2) **Series/Parallel Control.** Figure 2-64 illustrates the series/parallel system. In this system, steam pressure is used to control the fuel feed rate and steam flow to control the air flow rate. A combination air-flow and steam-flow meter is discussed in paragraph 2-28. Operators use this type of meter as a guide to control the relationship between air required to burn the fuel and air actually supplied. The steam generation rate is used as a measure of air required, while the flow of gases through the boiler setting is used as a measure of air supplied. By comparing the two, a check on the air to fuel ratio in the furnace can be obtained. This type of meter has been in use for many years and is commonly called a "boiler meter". The series/parallel control combines positioning control for the fuel with metering control for the air flow. Initial calibration and repeatability of the air flow signal are very important. Overfire air fans are also modulated with boiler load to obtain best combustion results at the lowest possible excess air levels. Although this feature has not been shown in figure 2-64, it would be provided for many applications.

d. Controls for Oil- and Gas-Fired Boilers. Parallel positioning and parallel metering type combustion controls are available for oil- and gas-fired boilers. Either type may be equipped with trimming control to adjust the fuel/air ratio based upon the oxygen level in the flue gas. Pneumatic, electric, electronic and computer-operated controls are available.

(1) **Parallel Positioning Control.** With the compactness of modern oil and gas burner packages, it is possible to use a single set of jackshaft and levers to control both fuel and air. Figure 2-65 illustrates a typical jackshaft system.

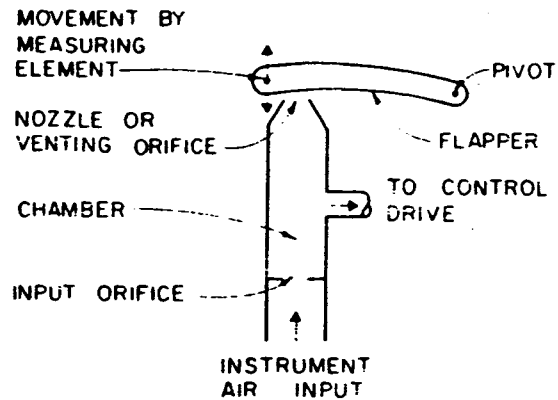


FIGURE 2-61. BASIC PNEUMATIC CONTROLLER

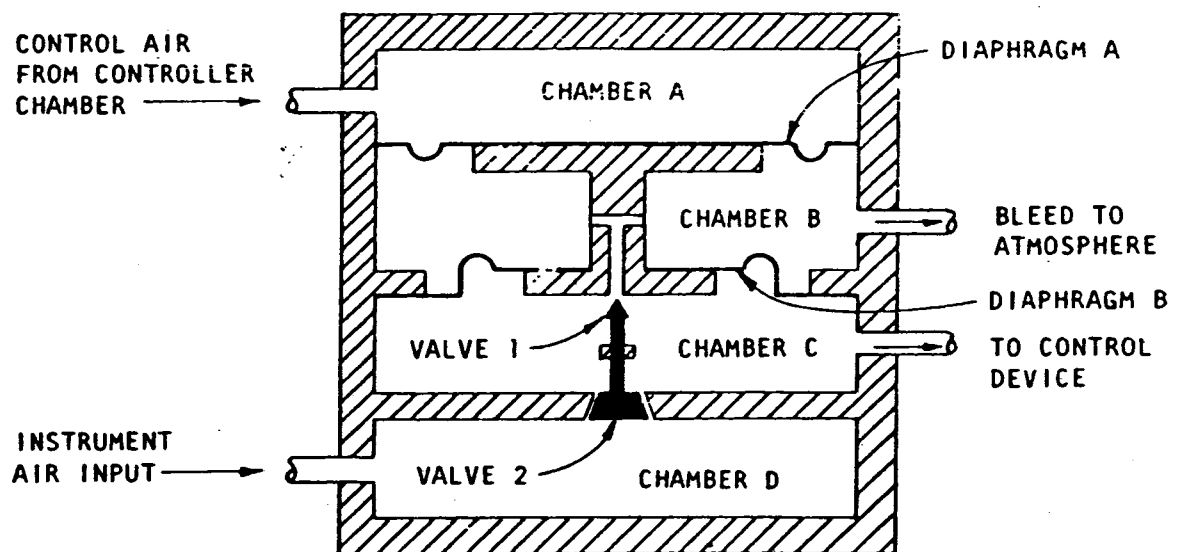
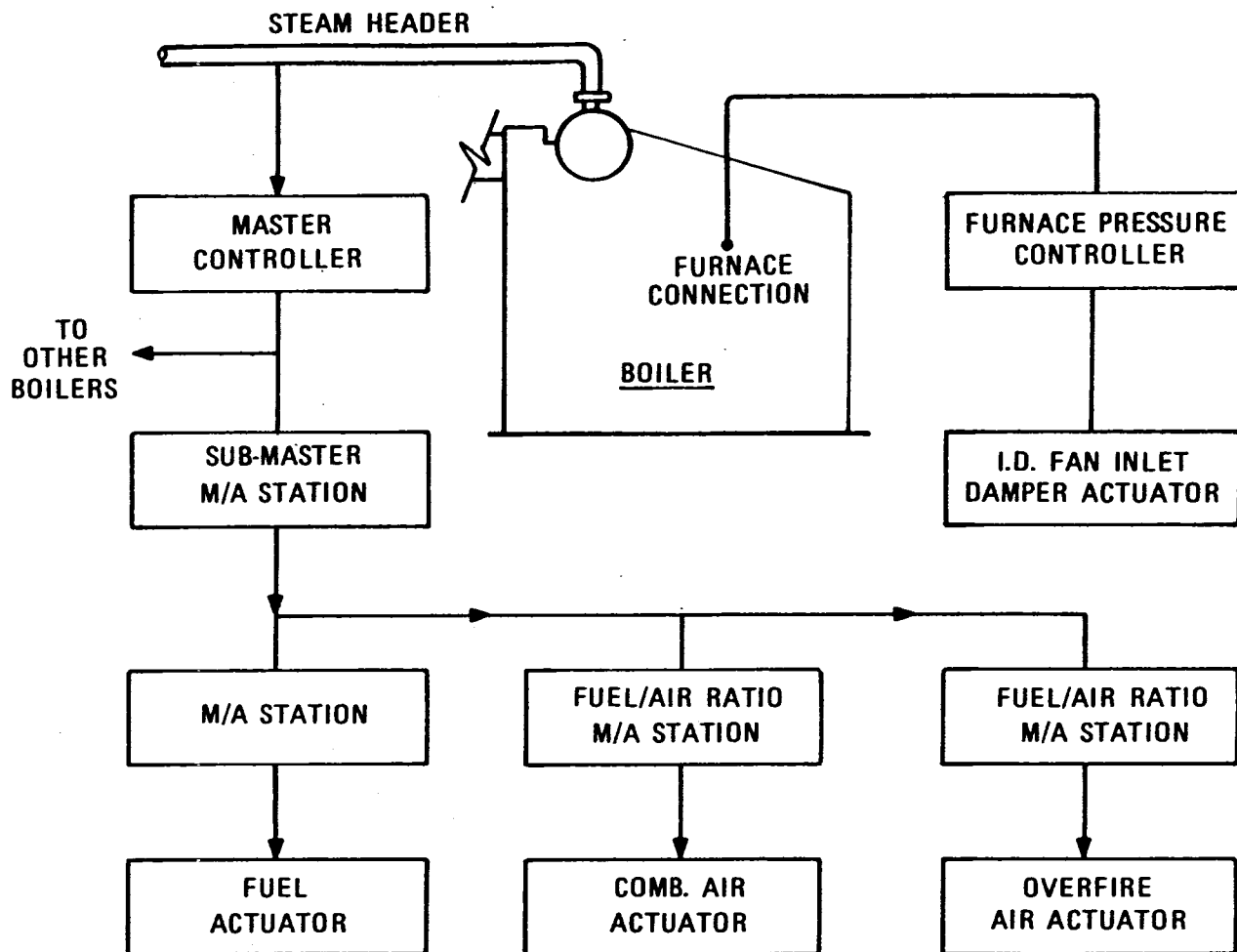


FIGURE 2-62. PNEUMATIC BOOSTER RELAY



M/A = MANUAL/AUTOMATIC

FIGURE 2-63. PARALLEL POSITIONING CONTROL SYSTEM

The master regulator is a proportional control which senses steam pressure and generates a rotary output, which moves the jackshaft. Adjustable valves are used to control and characterize the fuel oil and gas flow. These valves, together with the mechanical linkage that connects them to the FD dampers, establish the fuel/air ratio. This system is effective if fuel and air conditions remain constant and the linkage is tight and accurately adjusted. Some parallel positioning control systems replace the jackshaft by using a pneumatically or electronically generated fuel/air ratio and individual actuators for each fuel valve and fan damper. This approach, which is illustrated in figure 2-63, can be more accurate and more easily adjusted or trimmed. Positioning control type systems assume that the fuel and air flows always change the same amount for each change in valve or damper position. They are open-loop type control systems.

(2) **Parallel Metering Controls.** If the fuel and air flow to the burner are metered, a controller can be used which receives feedback from the metering device and further adjusts the fuel or air actuator. This ensures that when a specific fuel or air flow is demanded, it is actually delivered to the fire. This becomes a closed-loop control system and is known as parallel metering control. A parallel metering system is illustrated in figure 2-66. TM 5-810-2, High Temperature Water Heating System, requires metering controls for hot water boilers with capacities greater than 20 million Btu per hour. This type of system is also commonly used on larger sizes of steam boilers.

(3) **Oxygen Trim Control.** On most modern oil- and gas-fired boilers, as well as many coal-fired units, oxygen analyzers are used as combustion guides for the operators. Oxygen content in the flue gas verifies proper fuel/air ratio. Control systems have been developed to allow automatic adjustment of the fuel/air ratio, based upon the reading of the oxygen analyzer. These systems are called oxygen trim control systems. Figure 2-67 illustrates a typical oxygen trim control, although many other arrangements are also available. These controls are not applicable to all systems because trim adjustments are small. If the accuracy of an actuator is plus or minus 5% and the trim required is 2%, oxygen trim will not be effective. The following conditions must exist before oxygen trim can be effectively added to a boiler.

(a) Air infiltration into the boiler must be minimal, since the trim controller cannot distinguish between air which entered through the burner and infiltration air. The flame could be starved for air at the burner and producing smoke, while still registering excess air at the analyzer. Trim control can also become unstable if the leakage rate changes.

(b) The combustion equipment must be capable of operation at the new fuel/air ratio. This can be tested manually. A burner cannot be expected to operate automatically at a low oxygen level if it cannot do so

manually.

(c) The existing combustion control components must be able to operate accurately. Oxygen trim can be expected to compound any deficiency in an existing system.

2-27. BOILER SAFETY CONTROL.

Boilers are equipped with safety devices to minimize the risk of low water- and explosion-related damage. Figures 2-48 through 2-50 illustrate typical safety systems. A typical oil- or gas-fired boiler safety control system includes the following components:

- Low water-fuel cutoff switch.
- High steam pressure or high water temperature switch.
- Flame scanner(s).
- Gas supply high-pressure switch.
- Gas supply low-pressure switch.
- Combustion air flow switch.
- Purge air flow switches.
- Fuel safety shutoff valves with closed-position switches.
- Fuel control valves with low-fire position switch.
- Manual valves, cocks, strainers, and traps.
- Atomizing steam or air switch(es).
- Atomizing steam or air shutoff and control valves.
- Low oil pressure switch.
- High furnace pressure switch (for boilers with induced draft fans).
- Fan motor switch(es).
- Control logic.

National Fire Protection Association Standards 85A (for single burner systems), 85B (for multiple burner gas-fired systems), and 85D (for multiple burner oil-fired systems) establish rules for operation of the equipment listed above. Notes on some of the more important items are given below.

a. **Control Logic.** Control logic provides for the following actions:

- Pre-purging the boiler below lightoff.
- Proper operation of limits and interlocks.
- Low-fire start and release to modulation sequence.
- Trial for igniter flame sequence. The igniter is shut off at the end of the trial for main flame.
- Trial for main flame ignition sequence.
- Main flame or normal operation
- Safe shutdown of the system.
- Boiler post-purge.

Electronic controls are available which receive the flame scanner signals and provide the control sequences listed above when connected to the proper switches, valves, and motor starters. The electronic controls are equipped with self-checking circuits which prove the controls to be operational. Figure 2-68 shows an electronic programming control incorporated into a simple control cabinet typical of a fire tube boiler application. Note that motor starters, draft

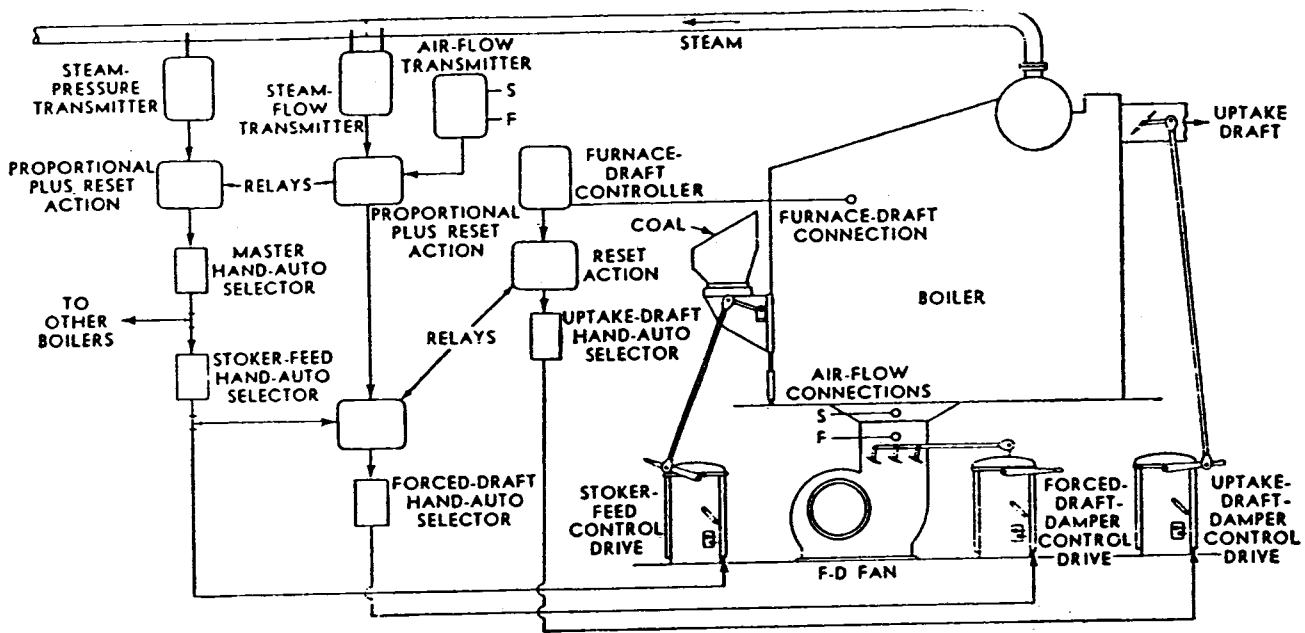


FIGURE 2-64. SERIES/PARALLEL CONTROL

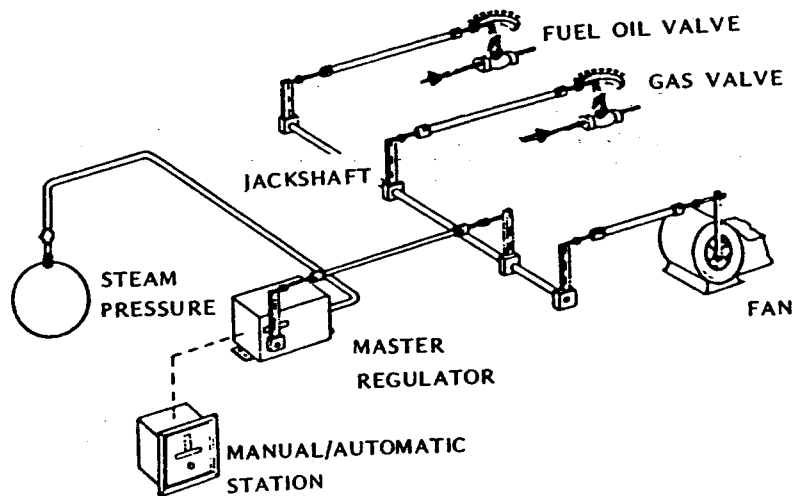
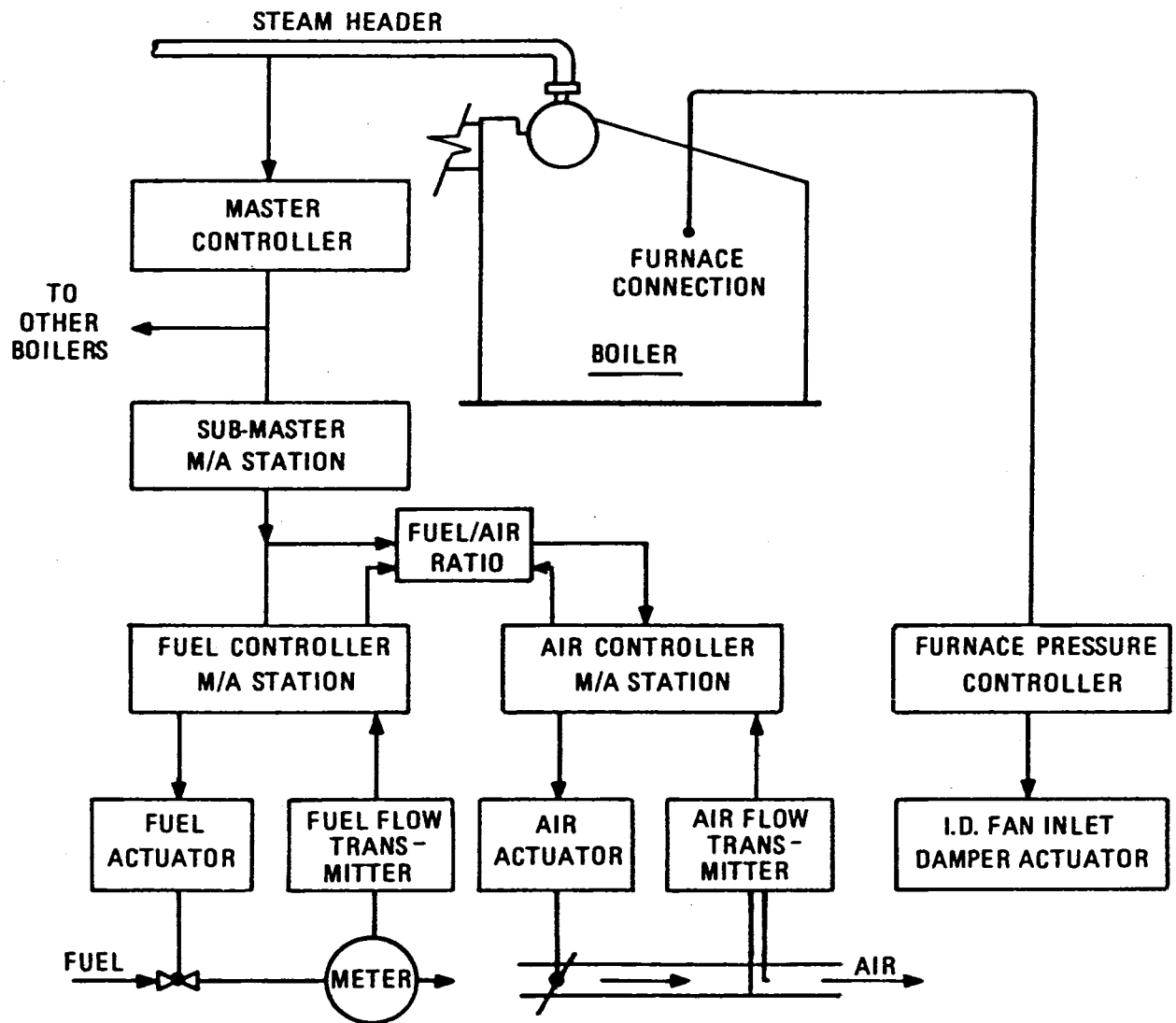


FIGURE 2-65. JACKSHAFT CONTROL SYSTEM



M/A = MANUAL/AUTOMATIC

FIGURE 2-66. PARALLEL METERING SYSTEM

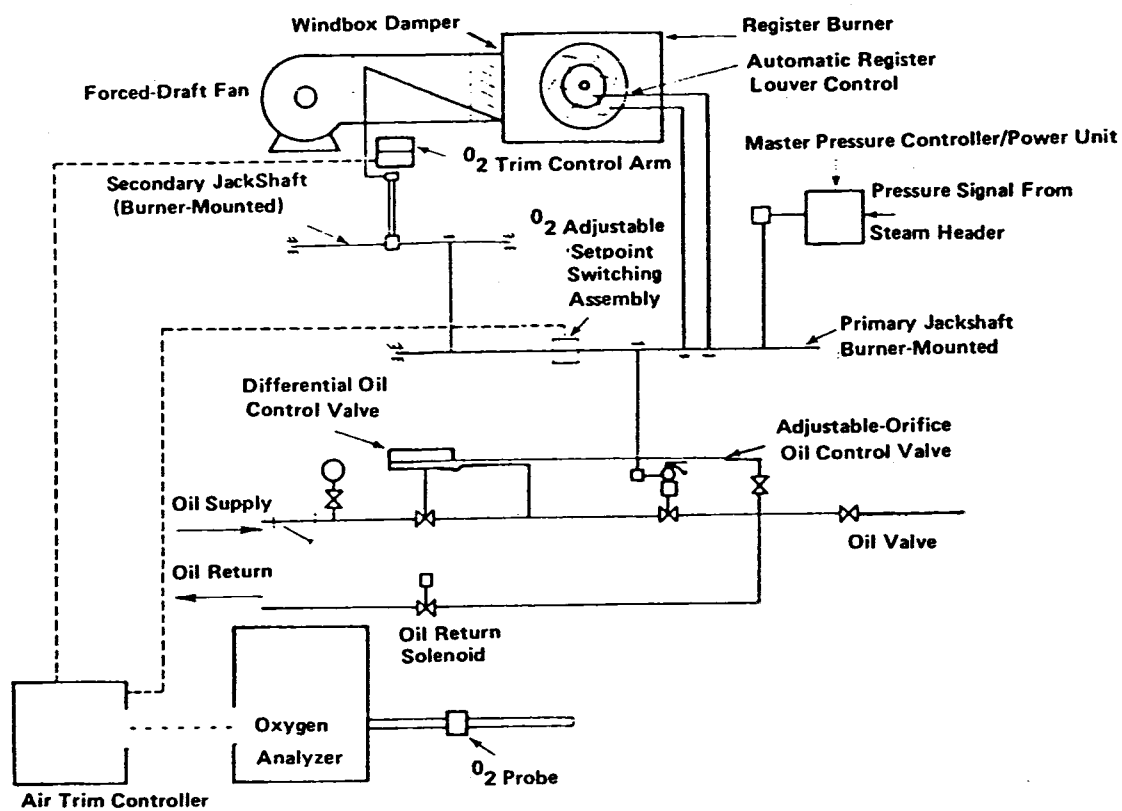


FIGURE 2-67. OXYGEN TRIM CONTROL SYSTEM

control, and a draft indicator are included. Relay logic has been commonly used in the past on multiple burner applications, but it is likely that in the near future, many new systems will be operated and monitored by programmable controllers.

b. Low-Water Fuel Cutoff. FLoat/magnet type and electrode-type low-water fuel cutoff devices are commonly used. Reference figures 2-69 and 2-70. Their purpose is to eliminate the major cause of boiler failure, firing a boiler with a low water level. If such a condition exists, the limit circuit is opened and fuel to the boiler is shut off. Because of its importance, the low-water fuel cutoff is a device that requires manual reset. The electrode type low-water fuel cutoff uses probes or electrodes to sense the water level. When the water level is above the low- water electrode, electricity is conducted to ground and a sensing relay coil is energized. Another relay is used to provide the manual reset feature required. Momentary electric circuitry can be provided to bypass the low-water fuel cutoffs to allow blowdown of the equipment without disrupting normal operation.

c. Pressure and Temperature Switches. A variety of different types of pressure switches are required to measure the wide range of pressures present in a boiler. Pressurs range from a few inches of water in the furnace to hundreds of pounds per square inch in the steam drum. Figure 2-71 illustrates a Bourdon-tube type pressure element with mercury-filled switch typically used for applications in the range of 5 to a few hundred psig. Diaphragm-type mechanisms with snap- action switches, as shown in figure 2-72, are used are air pressur measurements in the inches of water range. In both cases a change in system pressure causes the sensing element to deflect, activating the switch mechanism. Temperature switches can use liquid- or vapor-filled bulbs or bimetallic elements to activate similar switch mechanisms (reference figure 2-73).

d. Flame Scanners. Flame scanners which view the ultraviolet range of light are commonly called UV scanners. Lead sulfide type scanners which view the infrared and visible range of light are also common. Self-checking scanners, like the UV scanner shown in figure 2-74, are equipped with shutters thta allow the scanners electronic controls to prove that all of the scanner components are properly functioning. New types of scanners and electronics are also available which measure the frequency of the light observed and account for the fact that the base of a flame generates light at a frequency of many hundred cycles per second, while the tips generate light less than 60 cycles per second. Frequency scanners are especially effective in multiple burner applications because they can discriminate well between the flames from the various burners.

e. Annunciators. Figure 2-75 illustrates a typical annunciator system. Annunciators are frequently used in

boiler plants to perform the following functions:

- Provide continuous monitoring of important operating conditions such as temperature, pressur, level, vibration, main flame, bearing cooling, and other conditions associated with the boiler safety control and plant systems.
- Alert operators to off-normal condition(s).
- Require operator acknowledgment of off-normal condition(s).
- Advise operator when the condition returns to normal.

2-28. ADDITIONAL CONTROLS AND INSTRUMENTATION.

There are many types of controls and instruments which are applied to Army Boiler Plants. Some provide only measurement functions, while others provide both measurement and control. Some of the common types of instrumentation for measurement and control are discussed below.

a. Air-Flow Steam-Flow Meter. The air-flow steam-flow meter, which is also commonly called a "boiler meter", is typically applied in series/parallel combustion control systems to provide the operator with a guide to control the relationship between the air required to efficiently burn the fuel and the air actually supplied. A typical air-flow steam flow meter is shown in figure 2-76, and its application is discussed in paragraph 2-26. Essential parts of the meter are: two air-flow bells supported from knife edges on a beam which is supported by other knife edges, and a mercury displacer assembly, also supported by a knife edge on the beam. The bottoms of the bells are sealed with oil, and spaces under the bells are connected to two points of the boiler setting. The point of higher draft is connected to the left-hand bell and point of lower draft to the right-hand bell. This arrangement is similar to that of a flow meter, because it consists of a device for measuring a pressure or draft differential. Flow of gases through the boiler setting follows the same law as steam or water flowing through an orifice: the pressure differential, or "head," causing the flow is proportional to the square of the velocity. The flow meter is constructed so that movement of the pen on the chart is directly proportional to velocity. Therefore, if the airflow pen is to follow the movement of the steam-flow pen, the airflow mechanism must be compensated so that its movement is directly proportional to the flow of steam when the proper air-to-fuel ratio is being supplied. This compensation is accomplished by the airflow displacer, which is a parabolic float. Enough weight is placed on the system to cause the displacer to be submerged in mercury when there is no pressure differential on the bells. As the gas flow through the boiler increases, the right end of the beam moves up and the effective weight of the displacer increases. This reduces the amount of beam movement and, in turn,

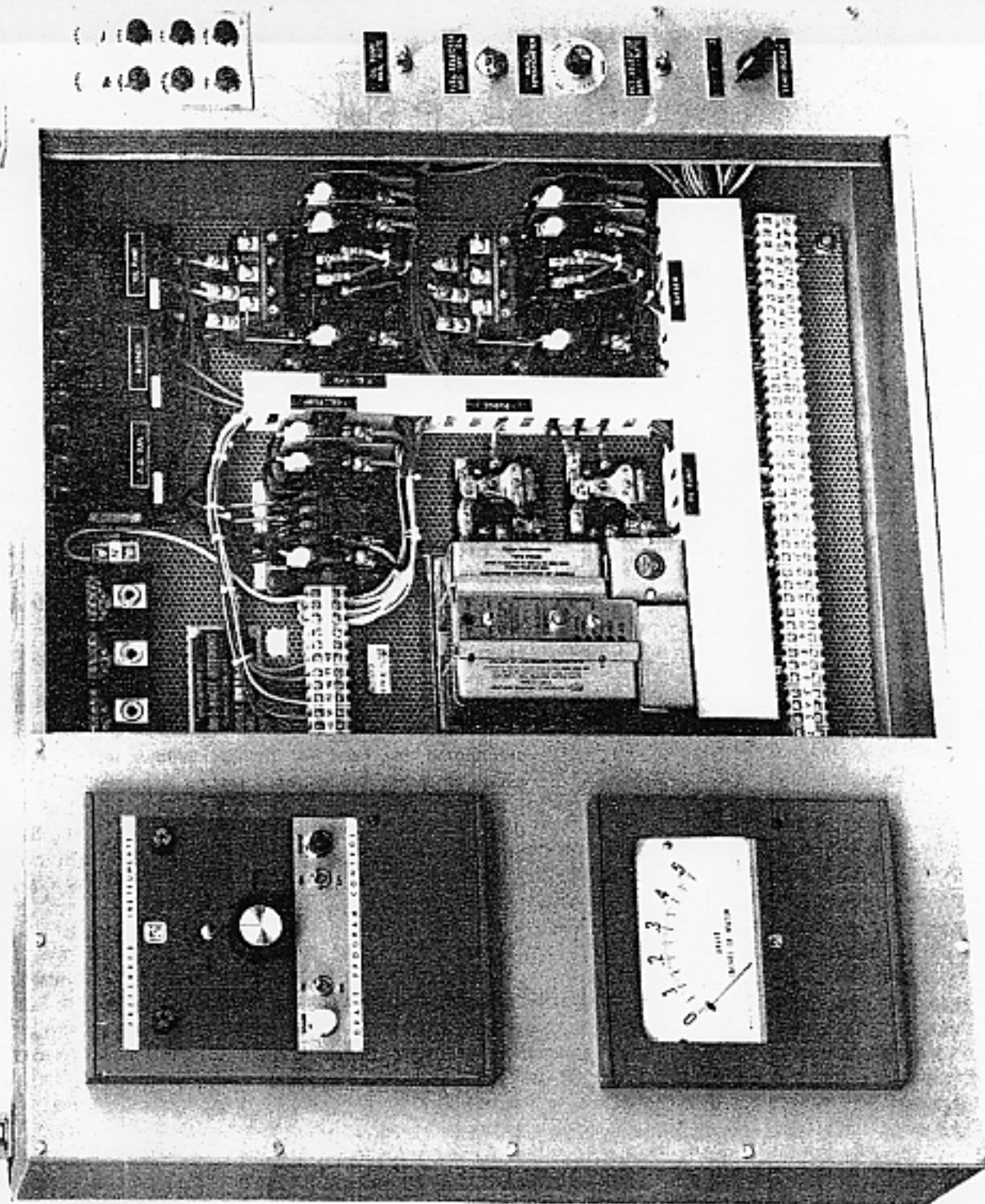
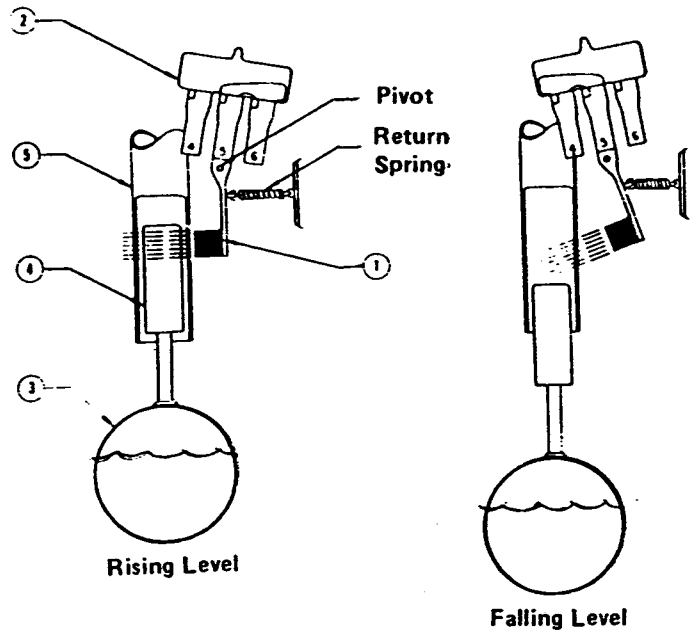
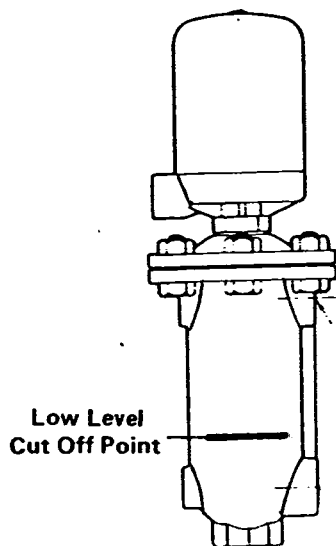


FIGURE 2-68. ELECTRONIC PROGRAMMING CONTROL IN A BOILER PANEL



OPERATING PRINCIPLE

A permanent magnet ① is attached to a pivoted mercury switch ②. As the float ③ rises with the water level, it raises the magnet attractor ④ into the field of the magnet. The magnet snaps against the non-magnetic barrier tube ⑤, tilting the mercury switch. The barrier tube provides a static seal between the switch mechanism and the float, eliminating the need for flexible bellows seals, packing glands or other failure prone sealing elements. When the water level falls, such as with a low water condition, the float draws the magnet attractor below the magnetic field. The magnet swings out and tilts the mercury switch to the reverse position, actuating the low water alarm and operating the burner cutoff circuit.

FIGURE 2-69. FLOAT/MAGNET
LOW-WATER FUEL CUTOFF

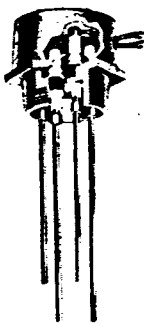


FIGURE 2-70. ELECTRODE TYPE LOW-WATER FUEL CUTOFF

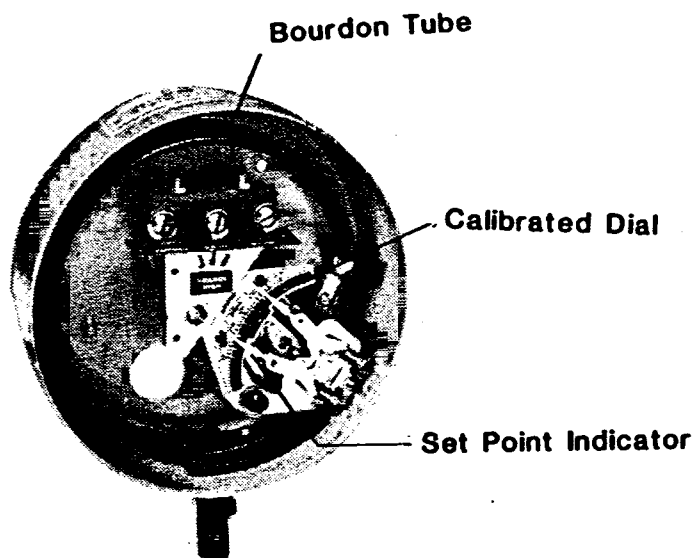


FIGURE 2-71. BOURDON-TUBE PRESSURE SWITCH

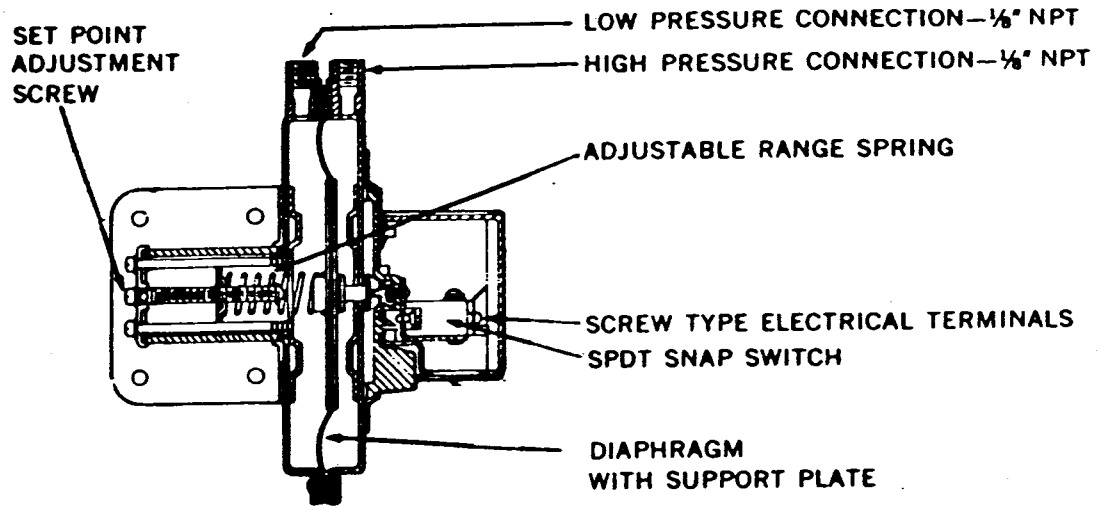


FIGURE 2-72. DIAPHRAGM PRESSURE SWITCH

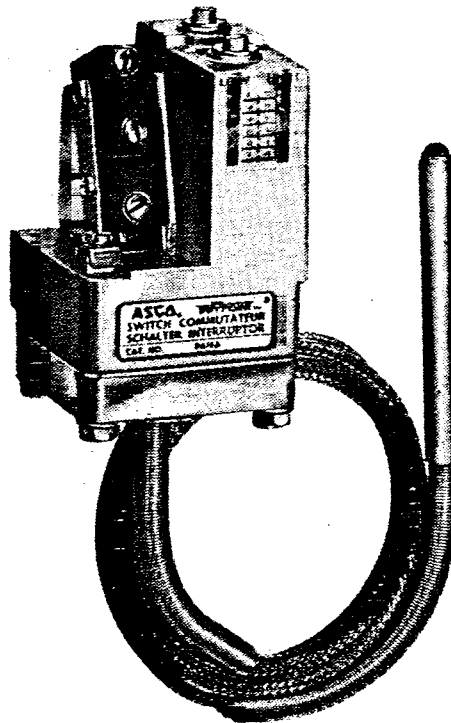


FIGURE 2-73. TEMPERATURE SWITCH

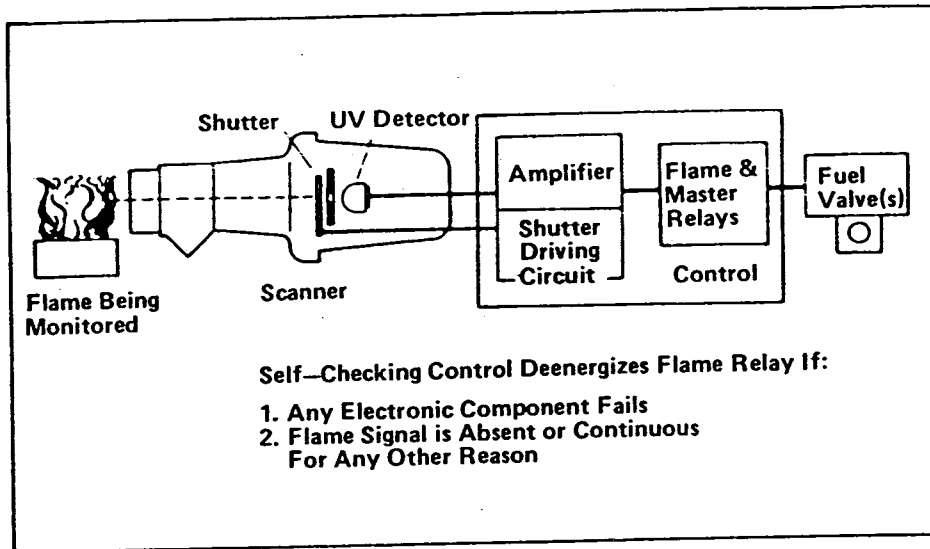


FIGURE 2-74. U-V FLAME SCANNER

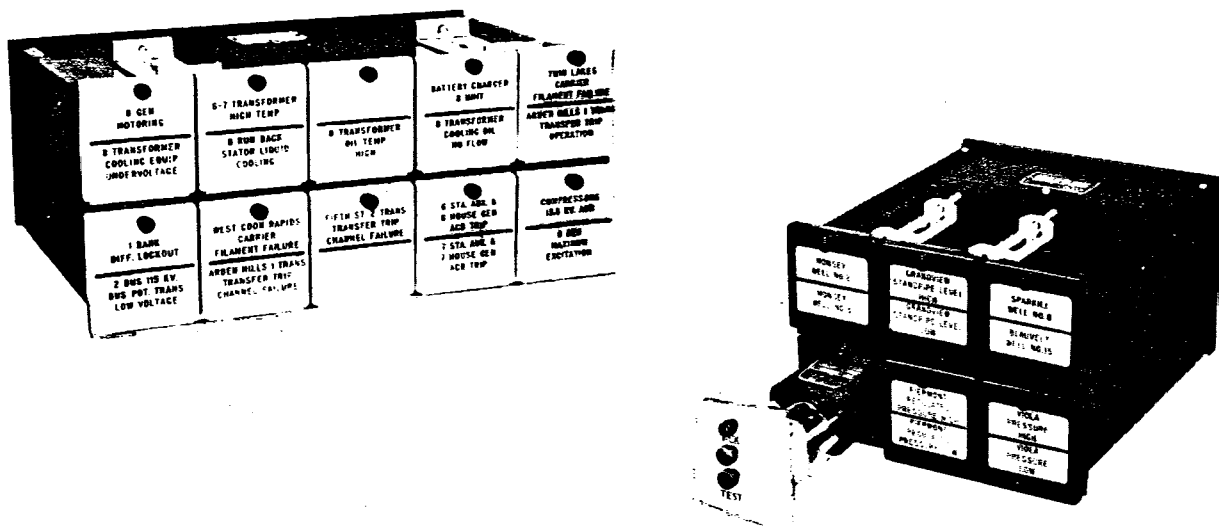


FIGURE 2-75. ANNUNCIATOR

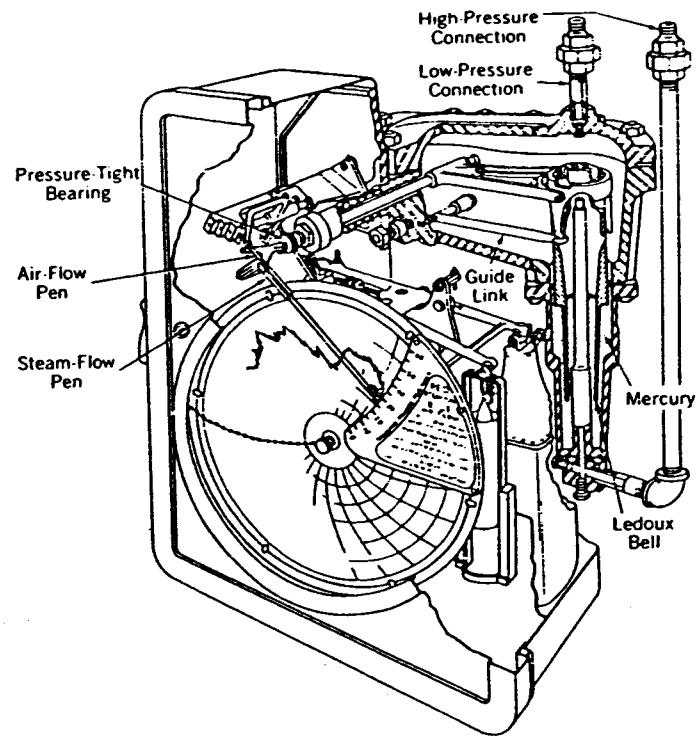


FIGURE 2-76. AIR-FLOW STEAM-FLOW METER

the amount of pen-arm movement. During initial startup, this mechanism is adjusted so that steam-flow and airflow pen recordings are together when the correct air-to-fuel ratio is being maintained. If, during operation, the airflow pen records higher on the chart than the steam-flow pen, the operator has an indication that too much air is being supplied, and vice versa.

b. Temperature Controls. Direct-acting, pilot-operated, and pneumatic or electronic temperature controls are available. Direct-acting temperature control regulators, as shown in figure 2-77, consist of a bellows-operated valve directly connected by capillary tubing to a temperature bulb. The bellows, capillary, and bulb systems are filled with a liquid, gas, or liquid-vapor combination. The bulb is inserted wherever temperature is to be controlled, as in a feedwater heater or hot-water heater, and the valve is mounted in the steam or hot-water line supplying the heat. Temperature changes at the bulb produce an expansion or contraction of the bellows and subsequent movement of the valve stem. An adjustable compression spring opposes expansion of the bellows and provides a means to adjust the controlled temperature. Direct-acting regulators, while simple, reliable, and inexpensive, are of limited capacity, and the valve and bulb must be located within the practical length of the pillary.

(1) Pilot-Operated Valves. Pilot-operated valves are available for larger capacity and more flexibility of installation. Pilot-operated valves may be operated by either internal or external pilot valves. A bulb and capillary system controls the movement of a small pilot valve. The variable loading pressure produced by the pilot valve controls the movement of the control valve. Figure 2-78 shows a pilot-operated temperature control valve. Both direct-acting and pilot-operated temperature regulators are proportional devices.

(2) Pneumatic and Electronic Temperature Controllers. For improved control accuracy, two-mode (proportional plus integral) temperature controllers are available using either pneumatic or electronic components. Filled bulbs, bi-metal elements, thermocouples, and resistance temperature devices (RTDs) are used as sensing elements. The pneumatic or electronic controllers compare the sensed temperature with a setpoint and generate an output to control an actuator/valve. The actuator may be either pneumatic or electric.

c. Pressure Controls. Pressure controllers may be divided into two general types. One type maintains a set pressure in one part of the system while the pressure in the other part fluctuates or changes within certain limits. An example of this type of control is a pressure-reducing valve, which maintains a set pressure on the discharge side by controlling the flow of steam, air, or gas. The second type of control maintains a constant pressure differential between two points and also controls the flow. This type of control is often

applied to a boiler feed water system to maintain a fixed differential between the pressure of water supplied at the feed valve and the pressure in the steam drum. The pressure controller may consist of either a self-contained device which operates the regulating valve directly, or a pressure-measuring device, such as a Bourdon tube, which operates a pneumatic controller. The controller positions the regulating valve or mechanism to maintain the desired conditions. Operation of pressure-reducing and differential-pressure valves depends upon a load applied to a diaphragm or piston, balancing the force exerted by a spring. The pressure load is applied to both sides of the diaphragm or piston in a differential-pressure valve, but to only one side in a pressure-reducing valve. A spring or weight is used to balance the valve in either case.

(1) Pilot-Operated Pressure-Reducing Valve. The valve shown in figure 2-79 is a self-contained pressure-reducing valve, which operates as follows: The deliver pressure acts on the bottom of the diaphragm, tending to push it up. This movement is opposed by the spring, and the diaphragm assumes a position dependent upon these two forces. The pilot valve is held against the diaphragm by a spring, so any movement of the diaphragm causes the pilot valve to move. One side of the pilot valve is connected to the supply pressure, and the other to the top of the piston which is in contact with the main valve. The spring on the bottom of the main valve holds the valve against the piston and supplies the force necessary to move the piston up. When the valve is in equilibrium (that is, when flow through it is sufficient to maintain the discharge pressure at the desired level), any drop in pressure on the discharge side causes the spring to push the diaphragm down and open the pilot valve further. The pilot valve, in turn, transmits a pressure to the chamber above the piston and causes the piston to move downward. This opens the main valve and increases the flow, building up discharge pressure until the valve is once again in equilibrium. The reverse occurs if the discharge pressure rises. Discharge pressure setpoint is regulated by adjusting the spring.

(2) Diaphragm Pressure-Reducing Valve. The valve in figure 2-80 is equipped with a diaphragm actuator and is used for many purposes. It is commonly connected to a pneumatic controller to serve as a pneumatic control valve. When used as a pressure-reducing valve, the pressure to be controlled is applied to the top chamber and a movement of the diaphragm is transmitted directly to the control valve. An increase in pressure pushes the diaphragm out against the resistance of the spring and closes the valve until equilibrium is established. The controlled pressure can be varied by adjusting the compression in the spring. Figure 2-81 illustrates a self-contained diaphragm pressure-reducing valve. The outlet pressure balances the force of the spring within the valve body. The remote pressure-sensing capability

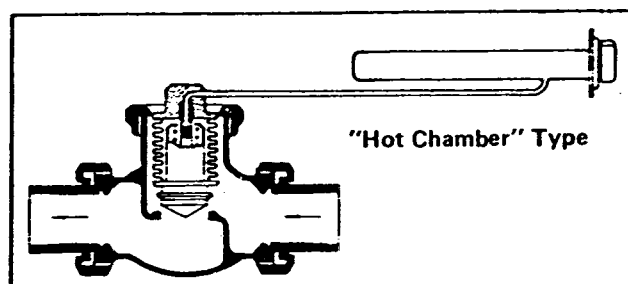
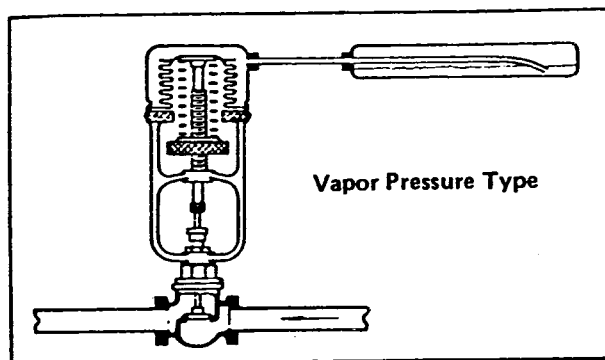


FIGURE 2-77. DIRECT-ACTING TEMPERATURE REGULATOR

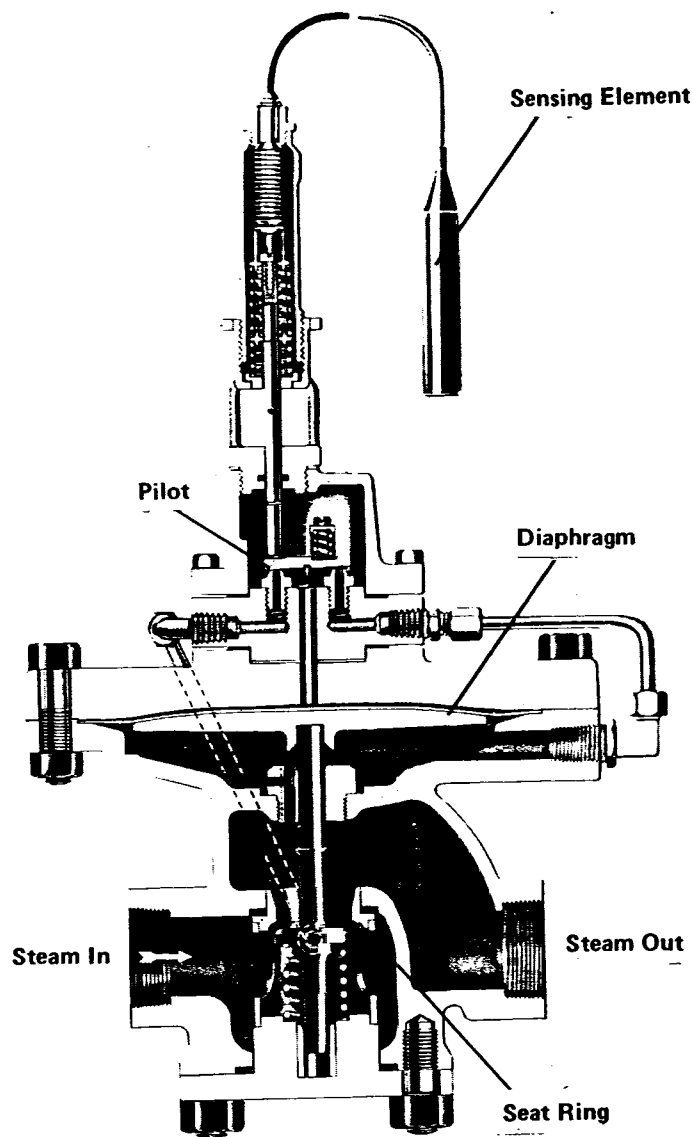


FIGURE 2-78. PILOT-OPERATED TEMPERATURE CONTROL VALVE

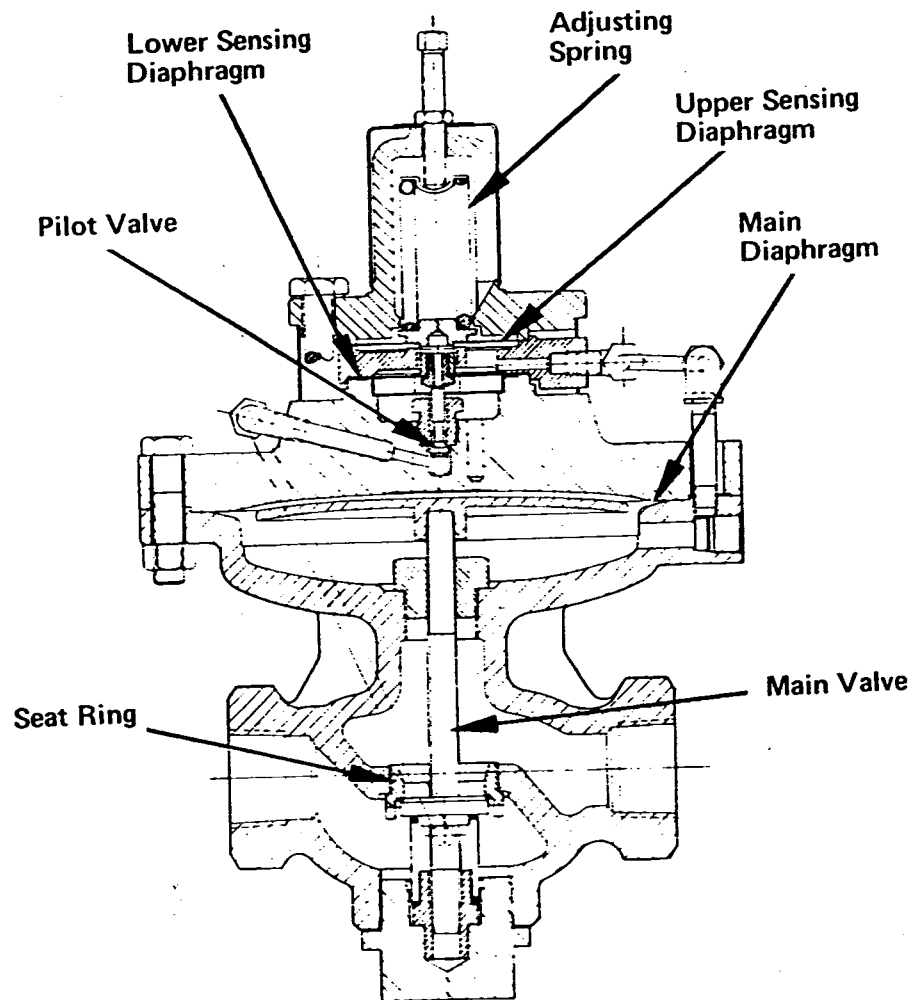


FIGURE 2-79. PILOT-OPERATED PRESSURE-REDUCING VALVE

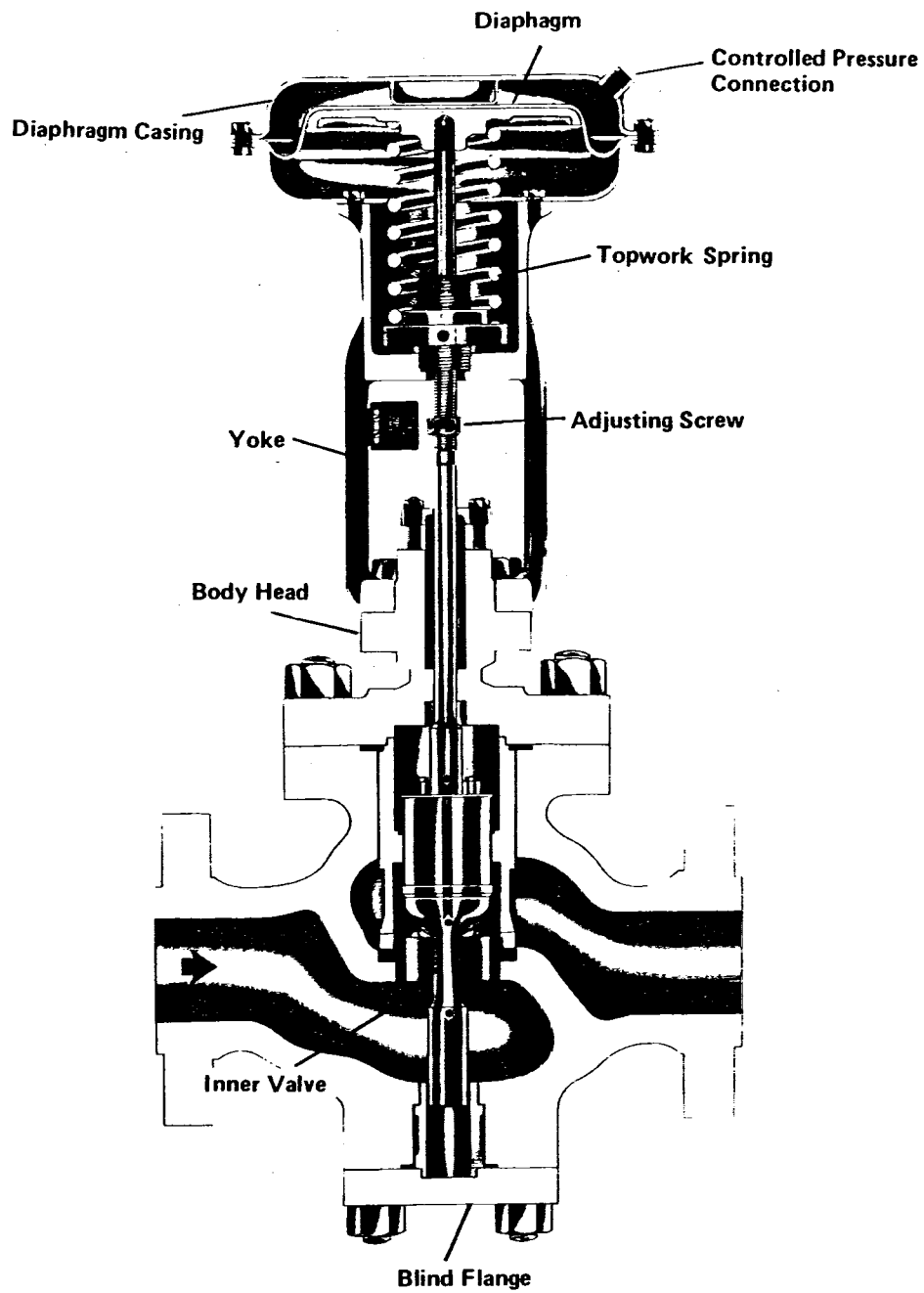


FIGURE 2-80. DIAPHRAGM ACTUATOR
PRESSURE-REDUCING VALVE

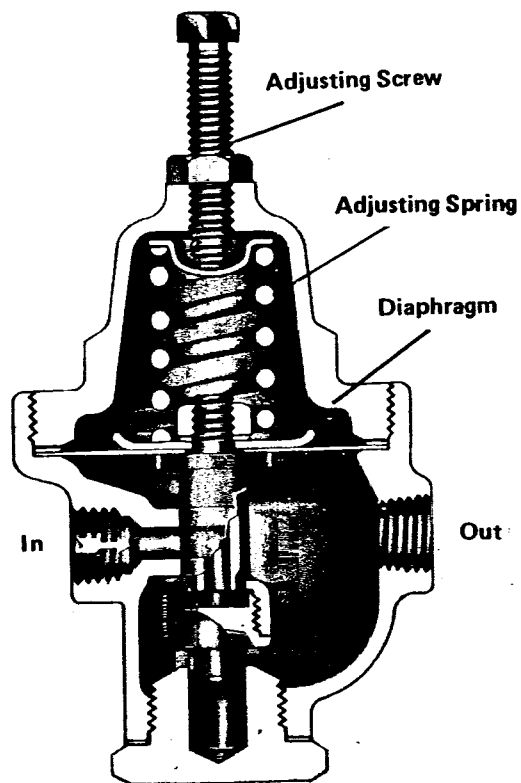


FIGURE 2-81. SELF-CONTAINED DIAPHRAGM
PRESSURE-REDUCING VALVE

of the previous valve is eliminated by the simplicity of this valve.

(3) **Differential Pressure-Reducing Valve.** In the valve shown in figure 2-82, a pressure-tight chamber is provided on each side of the diaphragm, and a spring is used to control the differential between the two pressures. The top and bottom chambers are connected to the two pressures to be controlled. When the force on the top chamber of the diaphragm is equal to the force on the bottom plus the spring force, the valve is said to be in equilibrium. If the bottom chamber pressure changes, the spring acts on the diaphragm to cause the pressures to vary simultaneously, maintaining a constant differential.

(4) **Steam Differential Pressure-Reducing Valves.** Figure 2-83 illustrates a differential pressure-reducing valve typically used to control atomizing steam to oil burners. An oil sensing line is connected to the top chamber of the valve. The pressure of the oil and spring are added together to balance the pressure of the steam and to adjust the valve position. The force applied by the spring establishes the differential pressure between the oil and steam.

d. Flow Meters. Five types of flow-measuring elements are typically found in central heating plants:

- Differential pressure
- Variable area
- Volumetric/positive displacement
- Propeller and turbine
- Weirs and flumes

These measuring elements may be connected to recorders, indicators, or totalizers to provide information on plant operation.

(1) **Differential Pressure Meters.** Differential pressure flow meters measure the pressure loss created by fluid flow through a pipeline restriction such as an orifice, flow nozzle, or venturi (reference figure 2-84). Water, steam, or gas flowing through a restriction increases in velocity and decreases in pressure. The pressure drop increases by the square of flow or velocity. Thus, if an orifice has a pressure drop of 100 inches of water at 100 percent flow, the pressure drop is only 1 inch of water at 10% flow. This explains why it is difficult for differential flow meters to provide accurate information at low flow rates. Figure 2-85 illustrates a steam flow recorder equipped with a Ledoux bell. The Ledoux bell is shaped to take the square root of a signal from the line restriction. The movement of the bell is transmitted through a system of levers and links to a pen which records the flow on a chart. Pneumatic transmitters like the one shown in figure 2-86 are available to replace the function of the Ledoux bell. Very accurate electronic transmitters are also available.

(2) **Variable Area Meters.** A variable area or rotameter is shown in figure 2-87. In this type of meter, the fluid passes upward through a tapered meter tube which contains

a float. The float position indicates the rate of fluid flow.

(3) **Volumetric Meters.** Volumetric or positive displacement meters are frequently used to measure gas, oil, or water and are equipped with a dial register that indicates the total volume of flow. Figure 2-88 illustrates a positive displacement-type meter for oil service. These meters can also be equipped to generate flow rate signals.

(4) **Turbine Meters.** In these turbine type meters, the rotational velocity of the propeller or turbine is proportional to the fluid velocity or flow. Flow rates are measured by electronic equipment which senses this rotational velocity and converts it to a volumetric reading. Figure 2-89 illustrates a turbine meter.

(5) **Weirs and Flumes.** Changes of liquid flow rates through the weir or flume causes a change in the upstream liquid level. Float-actuated level indicators are used to indicate flow rate.

e. Pressure Gages. A number of devices may be used to measure pressure, with the Bourdon tube being the one most commonly applied in boiler plants.

(1) **Bourdon Tube Pressure Gage.** The measuring element of the Bourdon tube gage (figure 2-90) is a tube of oval cross-section bent into an arc which is closed at one end and connected to the source of pressure at the other. This oval cross-section changes its shape with changes in pressure. When the pressure within the tube increases, the cross-section tends to become circular and causes the tube to straighten. The movement of the free end of the Bourdon tube is transmitted through a gear sector and pinion to a pointer which indicates the change in pressure. The exact shape of the tube and the material from which it is made depend upon the pressure range for which the gage is to be used. This type of gage can be used to measure pressures either above or below atmospheric. When using a gage to measure steam pressure, a siphon or water leg must be used to ensure that the hot steam does not come into direct contact with the tube.

(2) **Other Types of Pressure Gages.** Diaphragm-type gages are used for measurement of small differentials in inches of water where total pressure does not exceed about 1 psig. For high static pressures, opposed bellows gages (figure 2-91) are available to read a wide range of differential pressures. They are suitable for reading fluid pressure drops through boiler circuits and can be used to measure differentials from 2 to 1000 psi at pressures up to 6000 psig, far above the ranges used in Army Central Boiler Plants. More sophisticated devices for the measurement of pressures and differential pressures are also on the market. Generally described as transducers, they are based on a variety of principles. Some examples are transducers using a strain gage mounted on a diaphragm, or those using a crystal which undergoes a change in electrical resistance as the element is deformed. Since such elements require

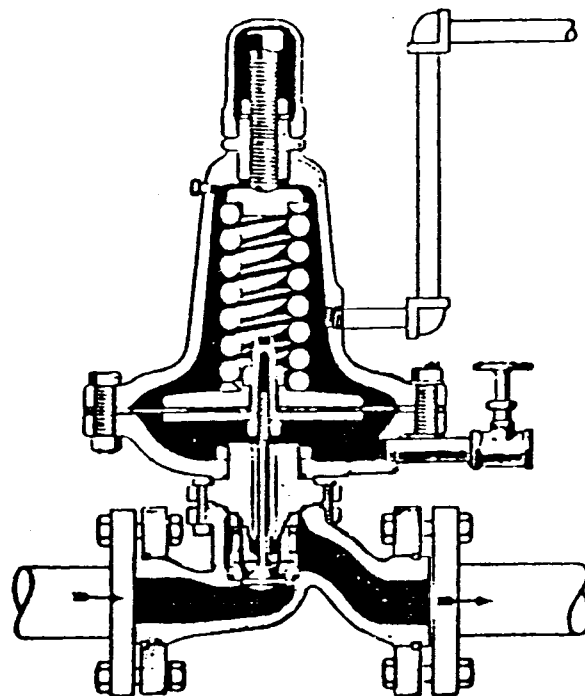


FIGURE 2-82. DIFFERENTIAL
PRESSURE-REDUCING VALVE

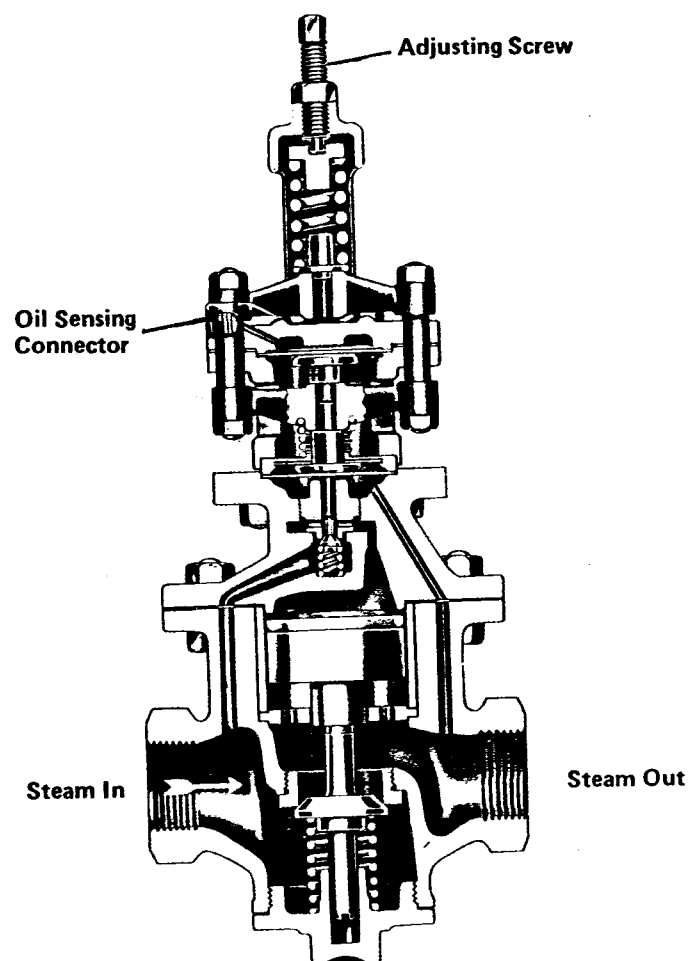


FIGURE 2-83. STEAM DIFFERENTIAL
PRESSURE-REDUCING VALVE

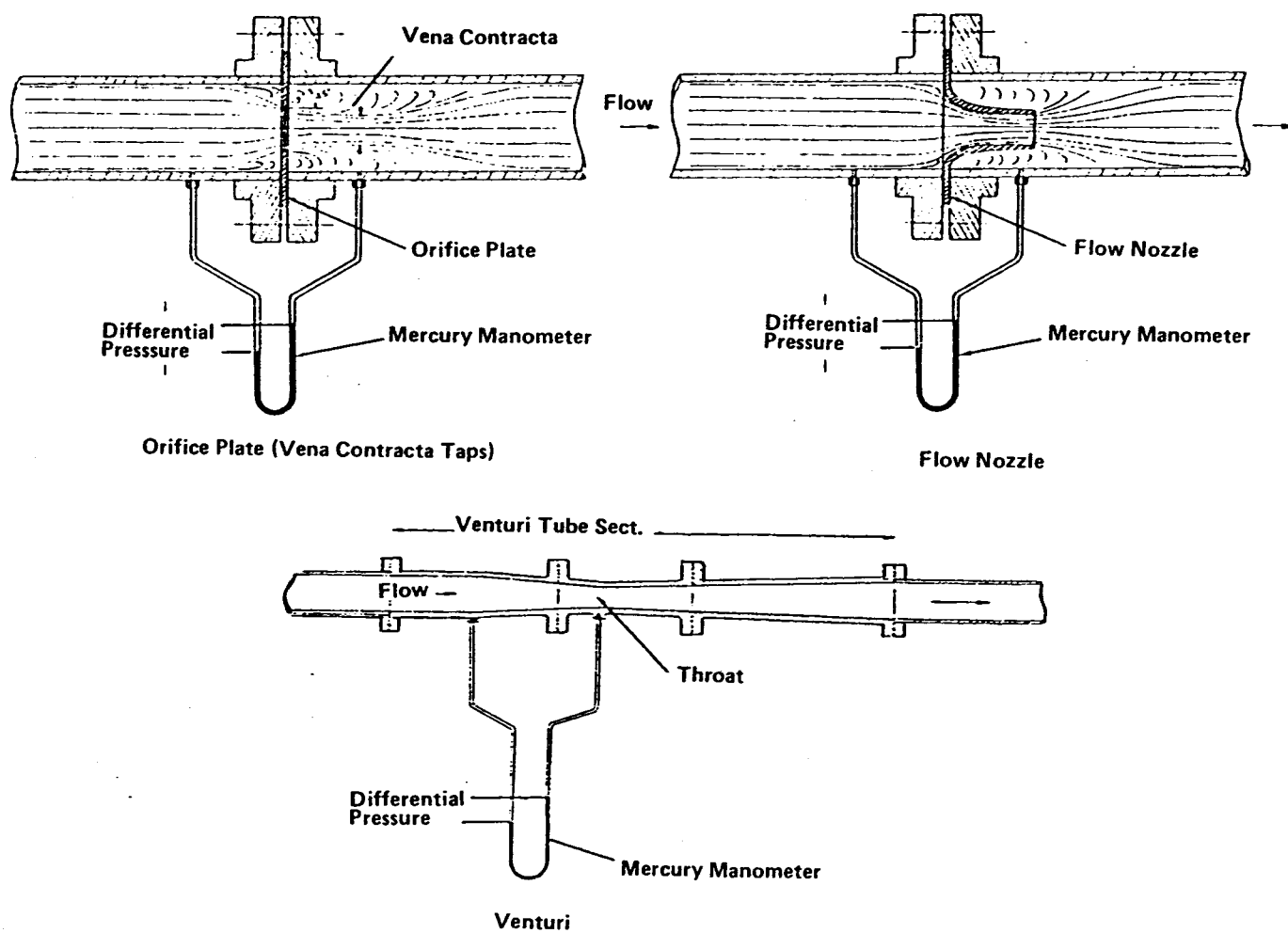


FIGURE 2-84. ORIFICE, FLOW NOZZLE, AND VENTURI

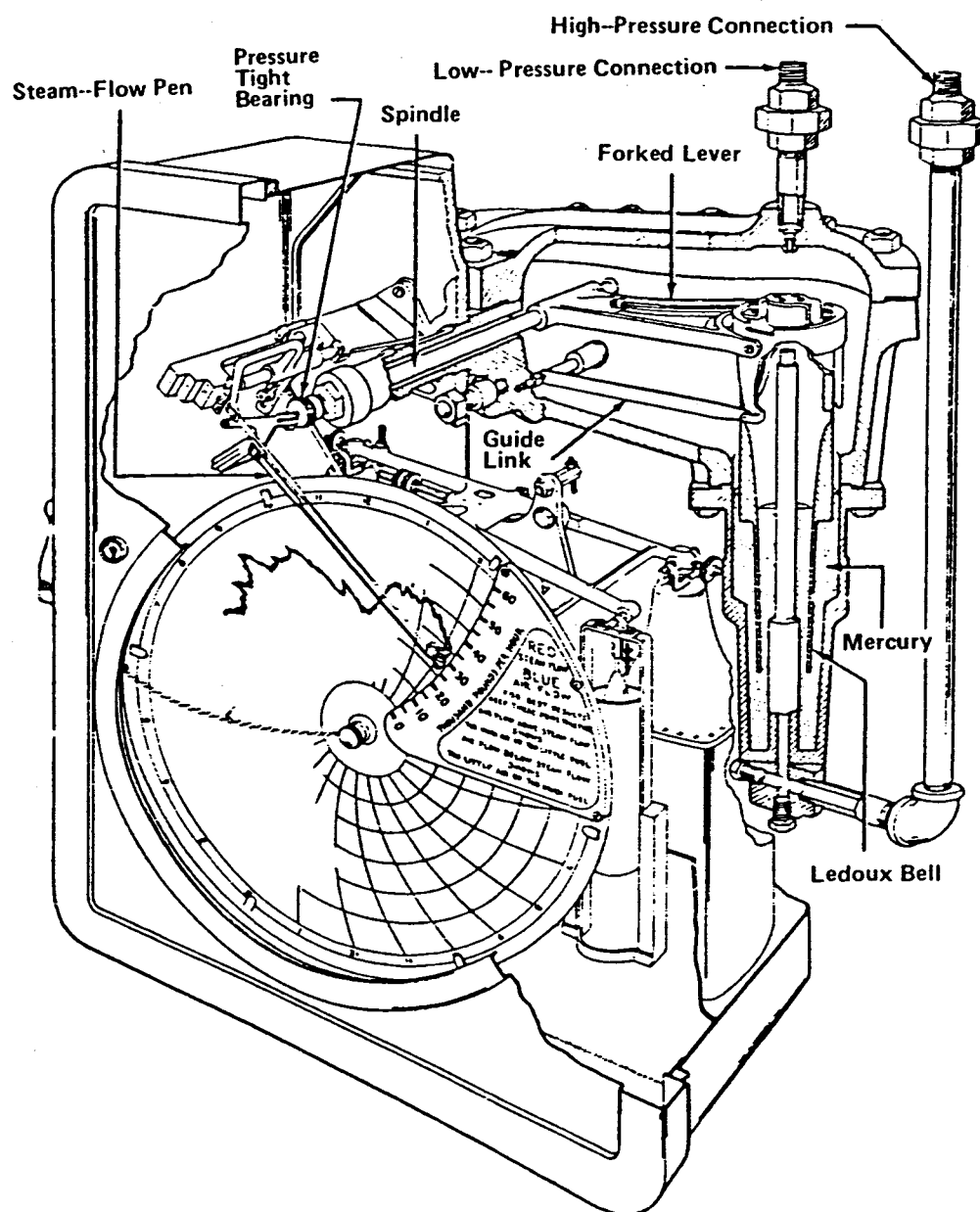
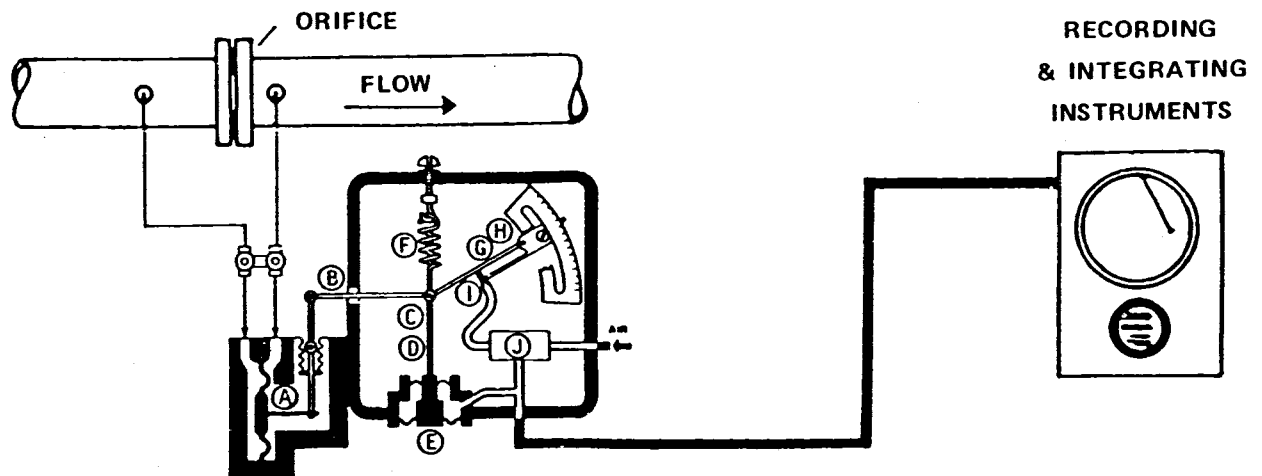


FIGURE 2-85 STEAM FLOW RECORDER



- | | | | |
|----|------------------------|----|-----------------|
| A. | DIFFERENTIAL DIAPHRAGM | F. | ZERO SPRING |
| B. | LINK | G. | BAFFLE |
| C. | FLOATING PIVOT | H. | PIVOT |
| D. | LINK | I. | NOZZLE |
| E. | FEED BACK DIAPHRAGM | J. | REVERSING RELAY |

FIGURE 2-86. PNEUMATIC DIFFERENTIAL PRESSURE TRANSMITTER

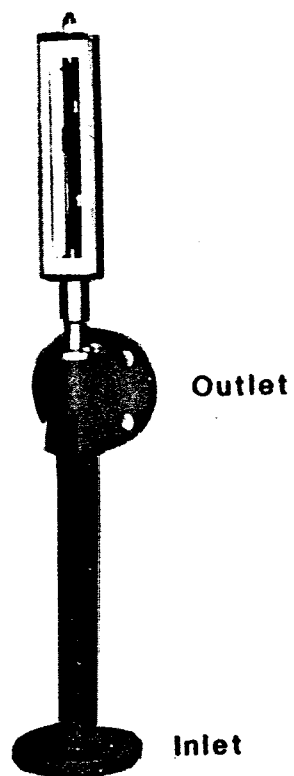


FIGURE 2-87. ROTAMETER

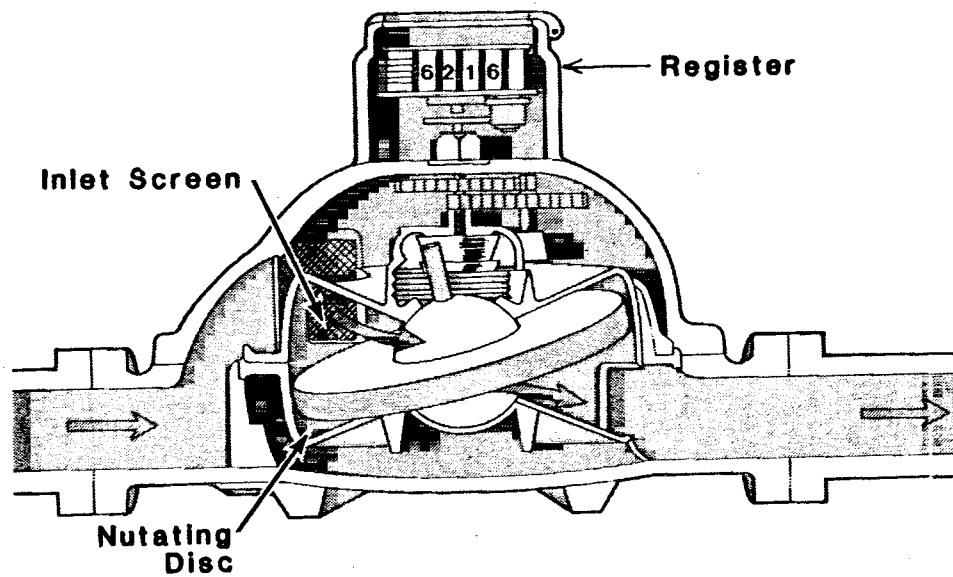


FIGURE 2-88. POSITIVE DISPLACEMENT METER

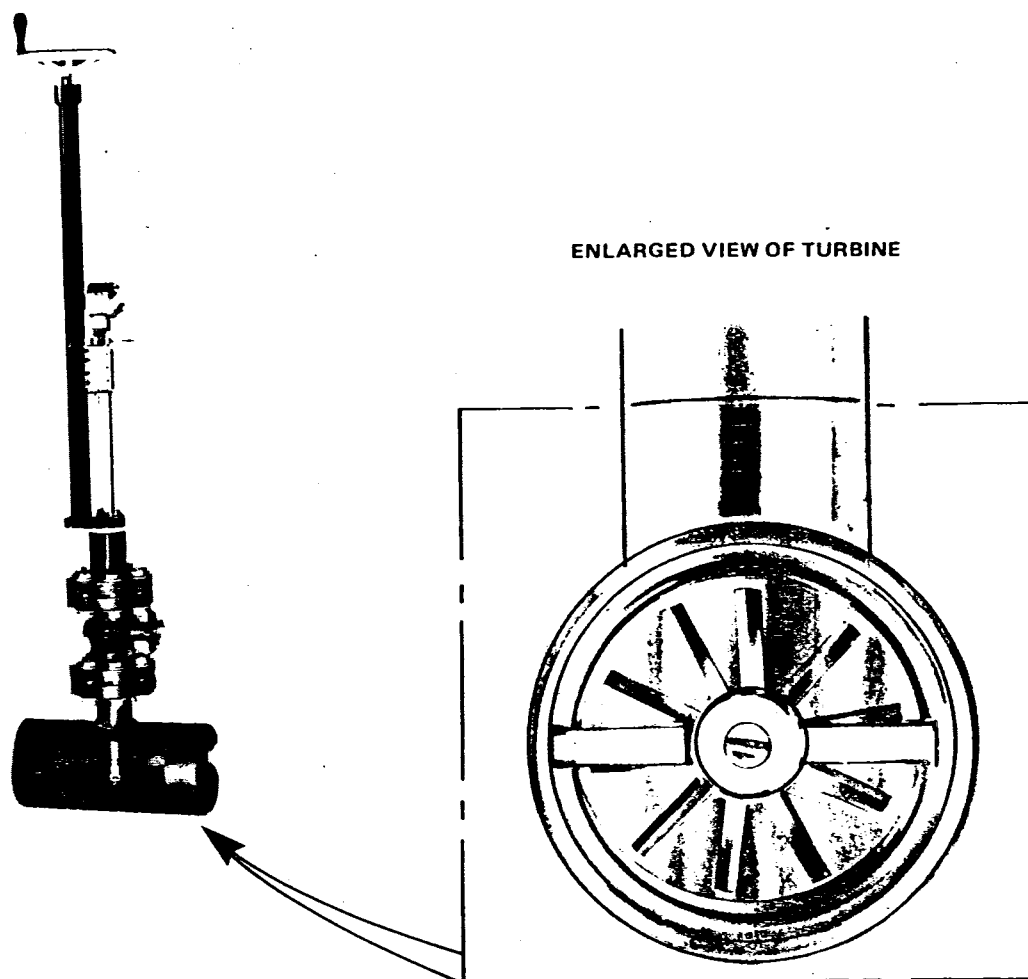


FIGURE 2-89. TURBINE METER

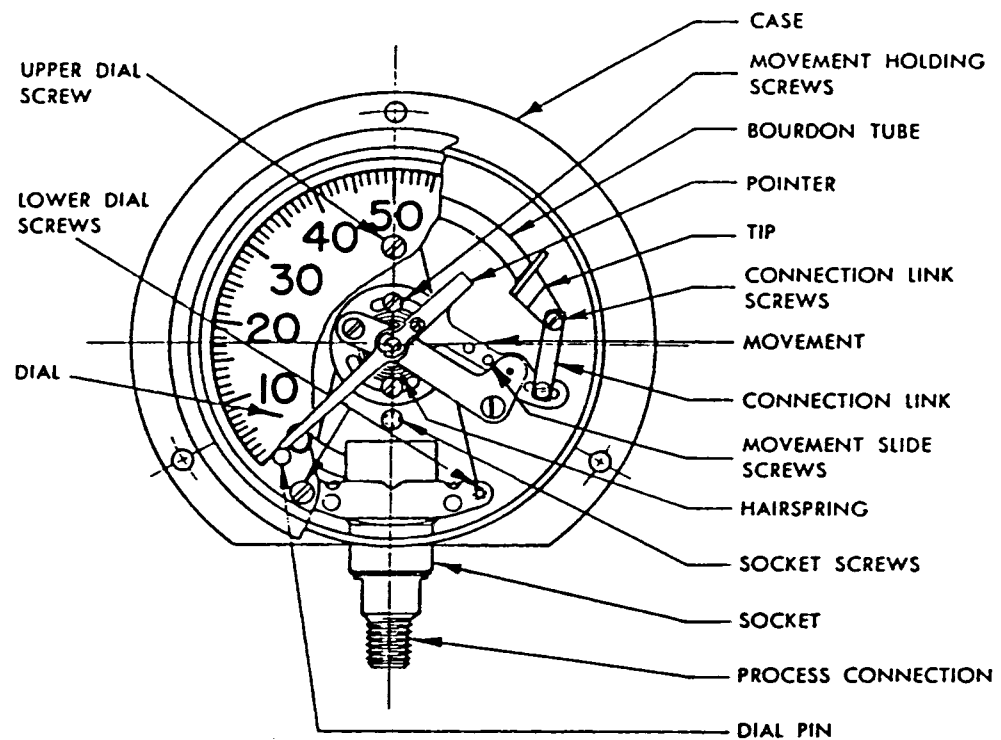


FIGURE 2-90. BOURDON TUBE PRESSURE GAGE

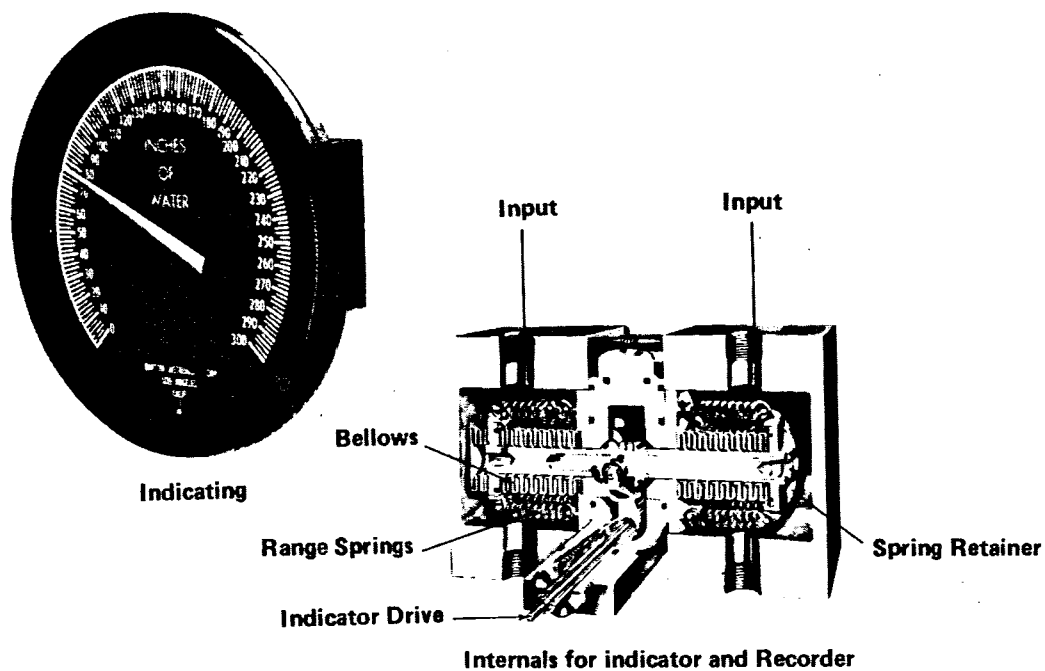


FIGURE 2-91. OPPOSED BELLOWS DIFFERENTIAL PRESSURE GAGE

elaborate and frequent calibration, they have not historically been used as basic instruments in Army Central Boiler Plants. However, with their rapidly increasing reliability and ease of application, pressure transducers are finding wider application and will become more frequently seen.

f. Draft Gages. A draft gage is a form of pressure gage which measures pressures in the range of inches of water column. Draft gages typically are used to measure air pressures at the furnace, windbox, and boiler outlet. Inclined and U-tube manometers and diaphragm-type draft gages are common.

(1) Manometers. Figure 2-92 shows an inclined and U-tube manometer. The inclined manometer consists of an inclined leg and a reservoir filled with gage oil. In a typical inclined manometer the length of the scales is 12 inches for each 1 inch of water draft measured. It is important to use the gage oil for which the manometer was designed to obtain accurate readings, since the gage reading is dependent on the density of the oil. This information is normally stamped on the manometer body.

(2) Diaphragm Draft Gages. The draft gage shown in figure 2-93 uses a thin metal diaphragm fastened to a flat cantilever spring. Atmospheric pressure is exerted on top of the diaphragm, and draft on the bottom. This pressure differential causes the diaphragm to move down. The downward movement is resisted by the cantilever spring. The motion of the cantilever spring is transmitted through a chain to the counterbalanced pointer and produces an indication on the scale which is directly proportional to the draft. The pointer in this gage moves in an arc. The area of the diaphragm is large, thus greatly magnifying the force available for moving the pointer.

g. Glue Gas Analyzers. A variety of flue gas analyzers may be installed in Central Boiler Plants. Their purpose is to allow the operator to more efficiently monitor and operate the plant and to ensure compliance with environmental regulations.

(1) Oxygen Analyzer. The percentage of oxygen in the boiler flue gas is an effective combustion guide. Continuous monitoring of oxygen levels can be accomplished by using a zirconium oxide oxygen analyzer shown in figure 2-94. The analyzer consists of a sampling system which pulls flue gas into the zirconium oxide cell located in an electric furnace. At approximately 1700 F, the cell responds to the percentage of oxygen in the flue gas by generating a small electric current. Analyzer electronics evaluate the electric current from the cell and produce an output signal to an indicator, recorder, or combustion trim control system.

(2) Carbon Monoxide Analyzer. Carbon monoxide (CO) in the flue gas indicates incomplete combustion due to either a lack of sufficient combustion air or inefficient

mixing of the fuel and air. Modern boiler plants may be equipped with CO analyzers to provide the operator with an indication of how much CO exists. The CO in the flue gas is converted to an electric signal through oxidation on the surface of a catalyst-coated element and measurement of the heat produced. Analyzer electronics provide an output signal proportional to the concentration of CO in the sample stream. The output is sent to a recorder, or occasionally used as a trimming input to the combustion control system. Historically, reliability has been a problem with CO analyzers. However, as technology improves, their reliability is expected to improve, and their use in combustion control systems will become more common. CO trim is applicable only to oil- and gas-fired boilers, and its use is limited by essentially the same criteria as those noted for oxygen trim systems in 2-26d(3).

(3) Smoke Density Indicator. Coal- and oil-fired plants are often provided with smoke-density indicators and recorders where smoke is particularly objectionable. These units usually consist of a light source and photoelectric cell mounted on opposite sides of the stack, an electronic system to condition the cell signal, and an indicator or recorder mounted on the panel.

(4) SO₂ and NO_x Analyzers. Continuous monitoring of pollutants is sometimes required by environmental regulations. Sulfur dioxide (SO₂) and oxides of nitrogen (NO_x) are the pollutants most commonly required to be monitored. Several different types of analyzers are available to monitor pollutants by extractive means: non-dispersive infrared (NDIR), ultraviolet photometric (UV), and electrochemical analyzers for both SO₂ and NO_x, chemiluminescence analyzers for NO_x, flame photometric and fluorescence analyzers for SO₂. Each of these types has its own advantages and disadvantages, and the technology is rapidly changing. A detailed analysis of up-to-date technology and environmental agency requirements is recommended before analyzers of this type are installed.

h. Temperature Gages. Temperature is measured by a number of devices, the most common of which is the mercury- or liquid-filled industrial thermometer. When remote indication or recording of temperature is needed, for example to monitor flue gas temperature leaving the boiler, then bulb/capillary, pneumatic, or electronic sensors and transmitters can be provided and connected to an indicator or recorder. Temperature devices can also be used to provide feed forward or feedback signals to a control system (reference paragraph 2-28b(2)). Figure 2-95 illustrates a typical recording thermometer.

i. Recorders. A variety of recorders is available to provide a permanent record of almost any variable which can be measured. Some recorders may be connected directly to the instrumentation which provides the recorded signal, such as the air-flow steam-flow meter shown in figure 2-

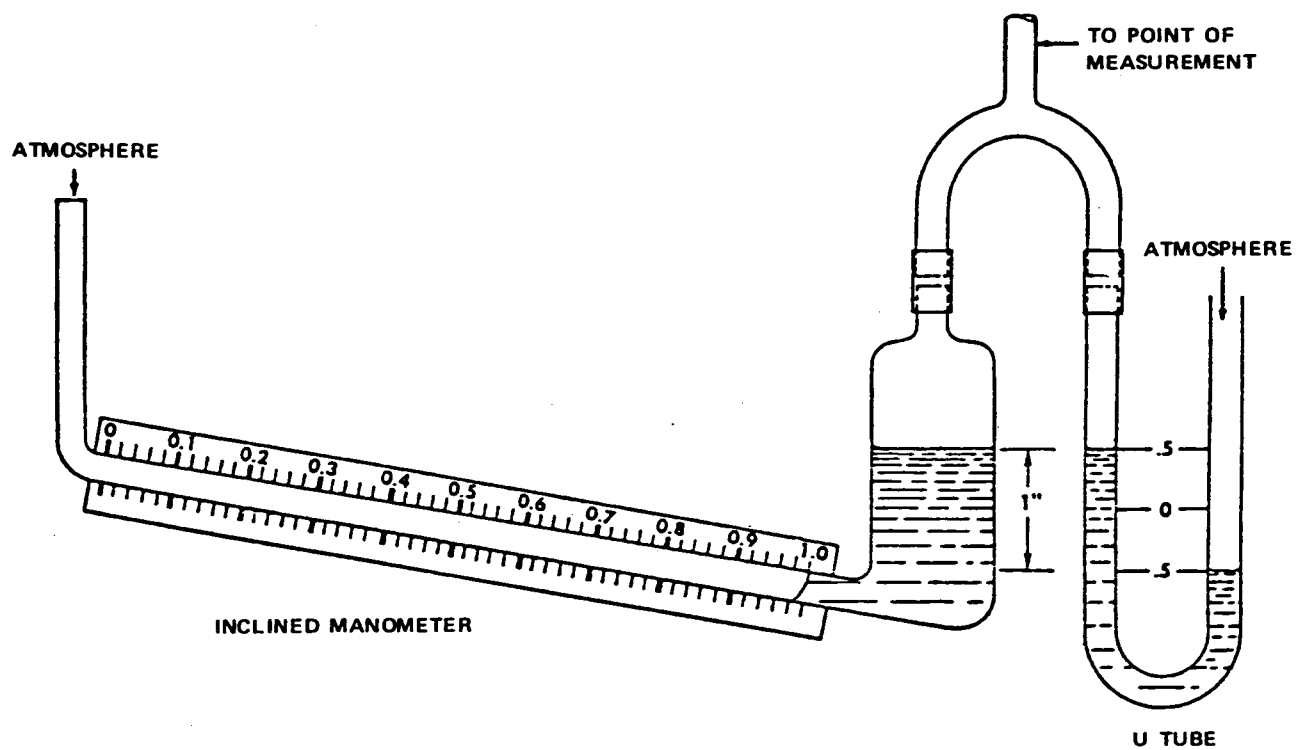


FIGURE 2-92. INCLINED/U-TUBE MANOMETER

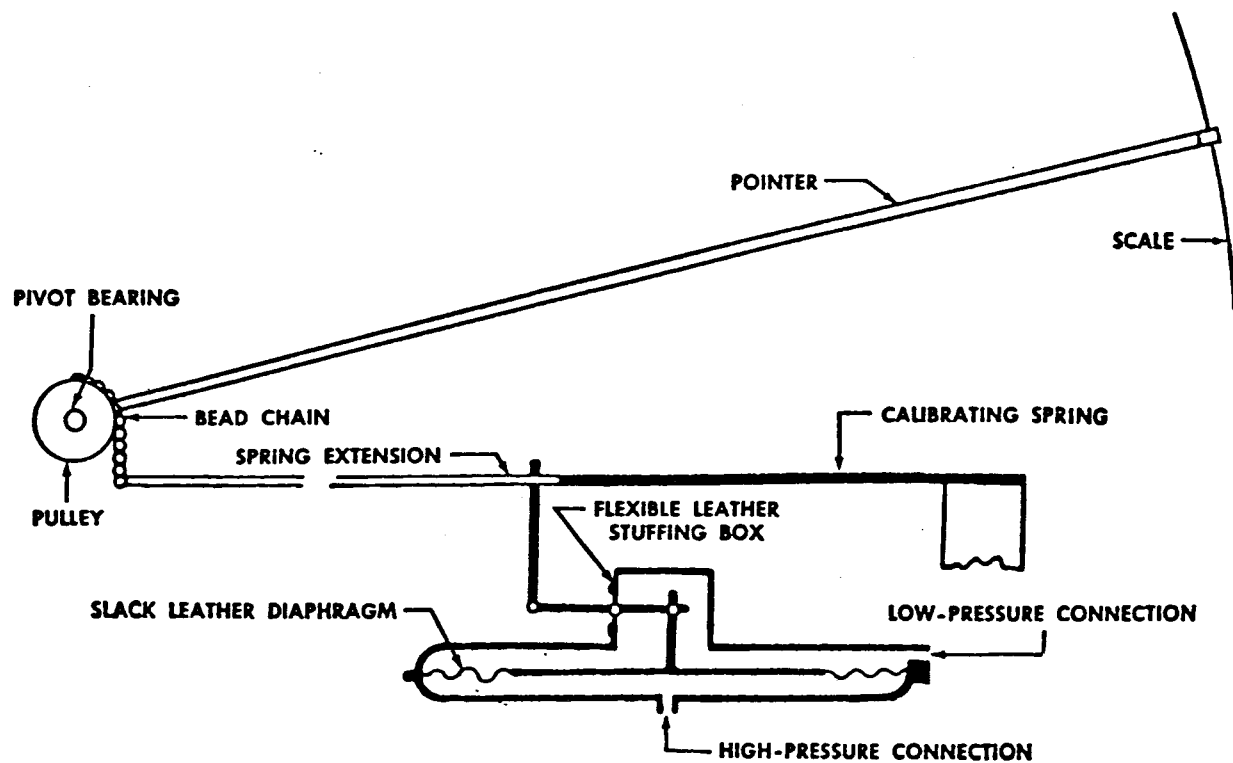
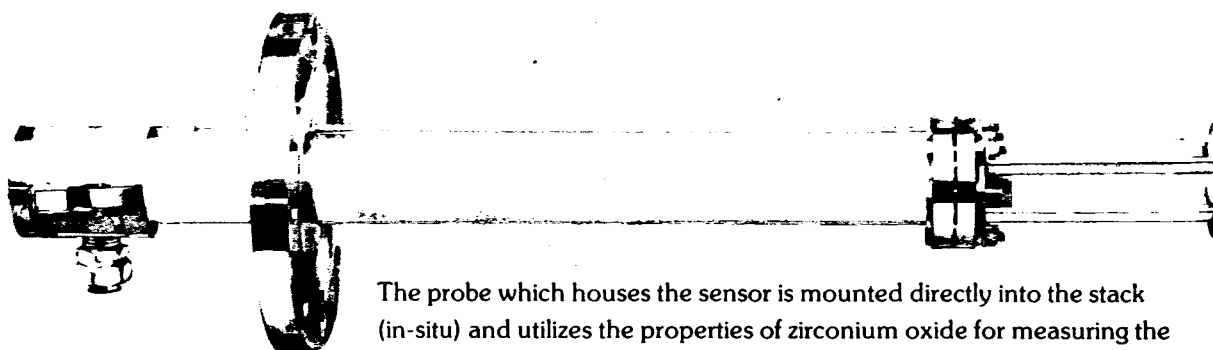


FIGURE 2-93. DIAPHRAGM DRAFT GAGE



The probe which houses the sensor is mounted directly into the stack (in-situ) and utilizes the properties of zirconium oxide for measuring the oxygen content. The process gas is admitted through a protective ceramic filter to the sample side of the sensor and produces an inverse logarithmic DC voltage signal which is sent to the temperature controller.

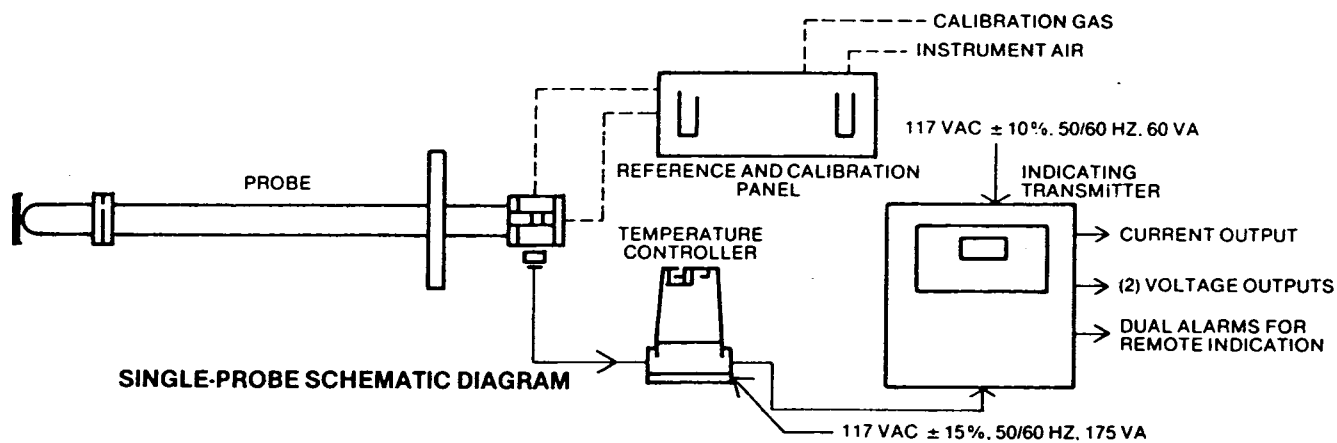


FIGURE 2-94. ZIRCONIUM OXIDE OXYGEN ANALYZER

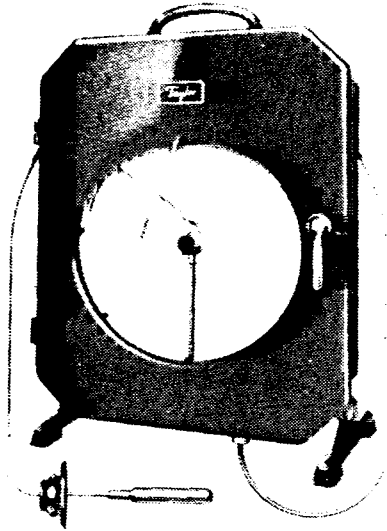


FIGURE 2-95. RECORDING THERMOMETER

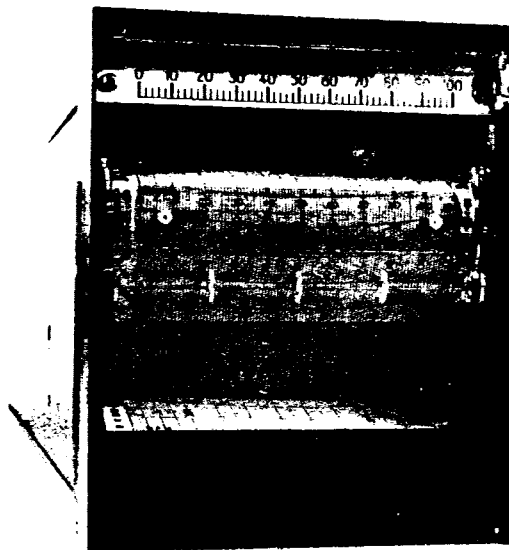


FIGURE 2-96. STRIP CHART RECORDER

76. Others are remotely mounted and receive an electronic or pneumatic signal from the instrumentation element. A typical strip chart type recorder is illustrated in figure 2-96. This particular model can record up to three separate process variables on a 4-inch-wide strip chart, while other models may record up to 20 variables. Both strip charts

and circular charts are in typical use in Army Boiler Plants and generally record two to four variables.

2-29. WATER TREATMENT CONTROL.

Instrumentation controls for water treatment systems are discussed in chapter 4.

SECTION V. POLLUTION CONTROL EQUIPMENT

2-30. POLLUTION REGULATIONS.

Control of pollutants from the combustion of fossil fuels in central boiler plants may be required. Boiler plant emission regulations are issued by Federal, state, and local environmental agencies, with the most stringent regulation usually being imposed. Two general types of regulations exist: point source regulations and ambient air quality standards.

a. Point Source Regulations. Point source regulations place limits upon the quantity of a pollutant which may be emitted from any stack, regardless of its relationship to local air quality. These regulations should be considered to be the minimum regulations, and, if applicable, must always be met. Typical point source emission levels for the commonly regulated pollutants are listed in table 2-1. In most cases, some or all of these regulations will be inapplicable to Army boilers. Federal regulations do not, at the present, apply to boilers of less than 250 million Btu/hr heat input (approximately 180,000-200,000 pounds of steam/fr). Most state and local agencies also have minimum size limitations.

TABLE 2-1.
TYPICAL POINT SOURCE EMISSION LEVELS
FOR VARIOUS POLLUTANTS

Pollutant	Fuel	Maximum Allowable Emission	
		LB-Pollutant/ Million Btu	PPM at 3% O ₂
Particulate	All	0.1	N/A
NO _x	N.G.	0.12	160
		Oil	0.3 230
		Coal	0.7 510
SO _x	Oil	0.8	440
		Coal	1.2 630

b. Ambient Air Quality Standards. Ambient air quality standards may be applicable to any size boiler. These standards require that the emissions from the unit be considered, as they affect the air quality of the surrounding area. Consideration must be given to meteorological effects and other pollution sources in the area in determining allowable emission levels. The emission levels determined under ambient air quality standards may be the same as, more stringent than, or less stringent than the applicable

point source regulations for a given boiler plant. The actual determination of the applicable limits usually warrants a separate study by a consultant.

2-31. TYPES OF POLLUTANTS AND CONTROL METHODS.

The pollutants listed in table 2-1 are those that are commonly regulated from Army boilers. Their generation and control are discussed briefly in this section. More detailed information can be found in TM 5-815.

a. Oxides of Nitrogen. NO_x is the generic name for a group of pollutants formed from various combinations of nitrogen and oxygen. The principal form generated by boilers is nitric oxide, NO. NO is formed when the nitrogen in the fuel and air reacts at high temperature with oxygen from the air. It can be controlled in existing boilers by careful adjustments and modification to the burners aimed at lowering the peak flame temperatures in the furnace and by minimizing the amount of free oxygen available in the highest temperature combustion zones. New boilers which have been purchased to meet specific NO_x emission regulations will generally have these modifications designed into them. In addition, they will also be designed with larger furnaces and more water-cooled surface in the burner zone to improve heat transfer characteristics and to further reduce the peak combustion temperature attained. Some of the modifications and adjustments which can be implemented are listed in table 2-2, as well as advantages and disadvantages of each and the anticipated reduction in NO_x emissions. Additional information on these NO_x reduction techniques is available in Army Manual TM 5-815. However, since relatively few Army boilers are required to meet NO_x regulations, these topics are not discussed further in this manual.

b. Oxides of Sulfur. The primary oxide of sulfur (SO_x) formed by the combustion of fossil fuel is sulfur dioxide or SO₂. SO₂ is formed when sulfur from the fuel combines with oxygen from the air in the high temperature zones of the furnace. In a conventional boiler, essentially all the sulfur that enters with the fuel converts to SO₂. No practical form of combustion modification has been developed to reduce SO₂ generation in the furnace. In order to control

Table 2-2. Comparison of NO_x Reduction Techniques

Technique	Potential NO _x Reduction (%)	Advantages	Disadvantages
Load Reduction	25-60	Easily implemented; no additional equipment required	Reduction in generating capacity; possible reduction in boiler thermal efficiency.
Low Excess Air Firing (LEA)	15-40	Increased boiler thermal efficiency	A combustion control system which closely monitors and controls fuel/air ratios is required; possible increase in particulate emissions; increased slagging and ash deposition with coal-fired units.
Two-Stage Combustion	40-50	—	Boiler windboxes must be designed for this application. Not recommended for coal-fired units.
Off-Stoichiometric Combustion (Coal)	15-45	—	Furnace corrosion and particulate emissions may increase.
Reduced Combustion Air Preheat	10-50	—	Control of alternate fuel-rich and fuel-lean burners may be a problem during transient load conditions.
Flue Gas Recirculation	20-50	Possible improvement in combustion efficiency and reduction in particulate emissions	Not applicable to coal-fired units; reduction in boiler thermal efficiency; increase in exit gas volume and temperature; reduction in boiler load. Boiler windbox must be modified to handle the additional gas volume; ductwork, fans, and controls required.

the release of SO₂ emissions to the atmosphere, it is necessary to either burn a fuel having a lower sulfur content, or use some type of flue gas desulfurization equipment (also called scrubbers) to remove the SO₂ after it leaves the boiler. The most common types of scrubbers used on boilers in the size range employed at Army bases are lime or limestone slurry types, magnesium oxide slurry, double alkali, and lime dry scrubbers. Some of the performance characteristics of these are summarized in table 203. The SO₂ removal systems mentioned above are expensive both to purchase and to operate, and in most cases they cost more than the entire boiler plant. For this reason, they are not cost-effective and generally not used unless dictated by regulations. They are very rarely seen on Army plants, compliance with regulations generally being by means of low sulfur fuel instead. Details on the installation and operation of scrubbing equipment is discussed in detail in Army Manual TM 5-815, chapter 10. Atmospheric fluidized bed boilers are also becoming more commonly applied when control of SO₂ emissions is required. These are generally more cost-effective than scrubbers but have not been commonly applied because of their limited operating experience (reference paragraph 2-18g).

c. Particulate. Particulate matter, also called fly ash, is the pollutant that is of most concern to Army boiler operators. It is comprised primarily of unburned carbon and the portion of the ash which is carried through the boiler by the flue gas stream. The quantity of particulate matter generated is strongly dependent upon the characteristics of the fuel. In general, the higher the ash content of the fuel, the higher the particulate emissions. Therefore, coal produces a large amount of fly ash, natural gas produces essentially none, and fuel oil produces a moderate but widely varying amount, depending upon its grade and characteristics. Particulate emissions may be controlled to a certain extent by careful attention to the burners and combustion characteristics of the boiler. However, control of this type is essentially limited to oil firing, since the total particulate matter produced from oil is low and usually contains a large percentage of unburned carbon. Proper combustion control can minimize this unburned carbon and thus substantially reduce the total particulate emission. With coal, the incoming fuel may contain 10 to 12 percent ash, as much as 80 to 90 percent of which may be carried out as fly ash. This ash far outweighs the small percentage of unburned carbon which is produced in the furnace due to incomplete combustion. Changes and adjustments to the burners which minimize the unburned carbon are, therefore, largely ineffective in reducing total particulate emissions. (This is not meant to imply that proper burner adjustment and operation should be ignored on coal-fired boilers, since gains in thermal efficiency can still be realized due to

a decrease in unburned carbon and reductions in excess air.) When coal is to be fired in a boiler, it is necessary to provide particulate emission control by means of a collection device in the flue gas stream between the boiler and the stack. Several suitable types of devices exist, as itemized in table 2-4 and discussed in sections 2-32 through 2-35. In addition to these devices, under some circumstances, tall stacks may be considered a particulate control device. Although they do not remove particulate matter, tall stacks can cause the particulates to be more widely dispersed in the atmosphere, and thus can be a means of meeting ambient air quality regulations. This technique is rarely applicable to Army boiler installations, however. For more details on the use of tall stacks as a particulate control device, refer to Army Manual TM 5-815.

d. Pollutants from Natural Gas. Of the fuels commonly burned in Army installations, natural gas is the cleanest. The only pollutant generally associated with natural gas is NO_x. Since natural gas contains no ash or sulfur, there is no generation of particulate matter or SO₂.

e. Pollutants from Oil. When oil is burned in a boiler, a variety of pollutants can be formed including NO_x, SO_x, and particulates. The grades of oil most commonly burned in Army facilities are No. 2 and No. 6. No. 2 oil is highly refined, clean-burning oil having little ash or sulfur and emissions can generally be controlled by burner adjustments without resorting to specialized pollution equipment. No. 6 oil is less refined and therefore cheaper. It can contain up to about 0.5 percent ash and 3.5 percent sulfur. These higher amounts of ash and sulfur lead to higher emission levels. Particulate emission levels from No. 6 oil often become high enough to warrant the use of particulate-control devices. While SO₂ emissions can also become high enough to violate regulations, the use of scrubbing equipment with small boilers is not generally cost effective, and regulations are usually met by conversion to an oil having a lower sulfur content.

f. Pollutants from Coal. Boilers burning coal will almost always require a device to control particulate emissions. NO_x and SO₂ emissions will also be high from most coals. Whether or not control of NO_x and SO₂ is required depends upon the regulation in effect in the particular locality in question. Control of NO_x emissions is accomplished by proper design, proper adjustment, and proper boiler and burner operation. Control of SO₂ emissions would usually be achieved by the use of low sulfur coal. In very few instances would the use of SO₂ scrubbing equipment be cost-effective on small boilers.

2-32. MECHANICAL COLLECTORS.

The term "mechanical collector" refers to a widely used type of particulate-collection device in which dust-laden

Table 2-3. Performance Characteristics of Flue-Gas Desulfurization Systems

System Type	SO ₂ Removal Efficiency (%)	Pressure Drop (inches of water)	Recovery and Regeneration	Operational Reliability	Retrofit to Existing Installations	Advantages	Disadvantages
Limestone, Scrubber Injection Type	30-40	Greater than 6"	No recovery of lime	High	Yes	High reliability; no boiler scaling.	Low efficiency; scaling and plugging of nozzles and surfaces in scrubber solids disposal.
Lime, Scrubber Injection Type	90+	Greater than 6"	No recovery of lime	Low	Yes	High efficiency; no boiler scaling; less scaling in scrubber than limestone in some cases.	Low reliability; solids disposal to landfill.
Magnesium Oxide	90+	Greater than 6"	Recovery of MgO and sulfuric acid	Low	Yes	High efficiency; no solids disposal.	Low reliability; corrosion and erosion of scrubber and piping; need pre-cleaning of flue gas.
Double Alkali Systems	90-95		Regeneration of sodium hydroxide and sodium sulfites	Unknown	Yes	Absorption efficiency potentially higher than other systems; scaling problems reduced; produces solid rather than liquid waste.	Solids buildup in reactor system; problems with dewatering systems.
Lime, Dry Scrubbing	70-90	8" - 10" including baghouse	Lime/limestone may be recovered	Unproven but potentially high	Yes	Lower cost; relatively simple operation; produces solid waste; takes advantage of alkali content of coal ash; uses existing technology.	Unproven operational reliability; applicable only to low/medium sulfur coal; must be used in conjunction with baghouse/precipitator.

Table 2-4. Performance Characteristics of Particulate Control Devices

Device	Maximum Removal Efficiency	Typical Pressure Drop	Advantages	Disadvantages
Mechanical Collector	90-95%	3-6	High reliability; well proven; compact.	Low efficiency on small particle sizes.
Electrostatic Precipitator	99%+	0.2-0.8	High efficiency over a wide range of particle sizes; well proven; reliable; low pressure drop.	High capital cost; very sensitive to ash analysis.
Fabric Filter	99%+	3-6	High efficiency; reliable if properly designed; insensitive to coal type.	Potentially high maintenance; high capital cost; not compatible with oil-only firing; maximum operating temperature of 550 °F.
Wet Scrubber	99%	20-25	High efficiency; can handle high temperatures and heavy loadings.	High capital cost; high O&M cost; solid waste disposal problems; complicated control system; water supply and disposal problems; weather-proofing may be required.

gas enters tangentially into a cylindrical or conical chamber or series of chambers and leaves through a central opening. The resulting vortex motion or spiraling gas flow pattern creates a strong centrifugal force which separates the dust particles from the carrier gas stream by virtue of their inertia. The particles migrate to the cyclone walls by means of gas flow and gravity and fall into a hopper. Because of the pattern of the gas flow through the collector, mechanical collectors are often referred to as "cyclones." Cyclones may be classified according to their gas inlet design, dust discharge design, gas handling capacity, collection efficiency, and their arrangements. Two common types of cyclones employed on Army boilers are the conventional, medium-efficiency, single cyclone, and the multicyclone.

a. Single Cyclone. Single cyclones are used to collect coarse particles when high collection efficiency and space requirements are not major considerations. Collection efficiencies of 50 to 80 percent of particles greater than 10 microns are common. A typical configuration is shown in figure 2-97. Single cyclones are 4 to 12 feet in diameter and are limited to about 20,000 actual ft³/min gas flow. More than one unit can be combined in parallel to accept greater gas flows.

b. Multicyclones. When higher collection efficiencies or higher gas flows are required, it is common to employ the multicyclone. This device combines into a single plenum a large number of small diameter cyclones (6 to 12 inches) of a type shown in figure 2-98. Due to the small diameter, higher inertial forces are generated and collection efficiencies are higher. In addition, it is possible to design multicyclones to handle virtually any gas flow simply by adding more cyclone tubes and mounting more than one unit in parallel into the gas stream.

c. Other Cyclones. Other types of cyclones which are less commonly used are the high-efficiency single cyclone and the wetted cyclone. The principal characteristics of the four types are summarized in table 2-5.

d. Collection Efficiency of Cyclones. The ability of a cyclone to separate and collect particles from a gas stream is dependent primarily upon the design of the cyclone, the size and quantity of the dust particles, and the pressure drop through the cyclone. Typical collection efficiencies for the various types of cyclones, operating in various applications, are given in tables 2-5 and 2-6. Efficiency estimates for a given application can be made by utilizing the cyclone manufacturer's fractional efficiency curves. An example of a typical fractional efficiency curve is shown in figure 2-99. These curves are determined by actual testing of similar prototypes in the manufacturer's laboratory. Total collector efficiency is determined by multiplying the percent weight of particles in each size range by the collection efficiency corresponding to that size range, and determining

the sum of all the collected weights as a percentage of the total weight of dust entering the collector.

e. Pressure Drop and Energy Requirements. Through any given cyclone, there will be a loss in static pressure of the gas between the inlet and outlet. This pressure drop is the result of entrance and exit losses, frictional losses, and loss of rotational kinetic energy in the exiting gas stream. The cyclone pressure drop increases approximately as the square of the inlet velocity. Energy requirements in the form of fan horsepower are directly proportional to the volume of gas handled and the static pressure drop. A rule-of-thumb estimate of fan energy requirements is that one quarter of one horsepower is required per 1000 actual ft³/min of gas per 1 in-H₂O pressure drop. Thus, a mechanical collector applied to a 40,000 lb/hr boiler (approximately 16,000 actual ft³/min flue gas flow) and designed to operate at 3.0 in-H₂O pressure drop would require about 12 horsepower in fan power.

f. Cyclone Performance. For cyclone installation, it is desirable to have as high a collection efficiency and as low a pressure drop as possible. Actual in-plant performance will vary from day to day due to changes in operating conditions such as gas flow, dust load, and particle size. In general, changes which increase pressure drop or particle size will improve the collection efficiency, which changes that decrease pressure drop or particle size will decrease efficiency.

g. Application for Particulate Collection. Mechanical collectors are used as primary particulate collection devices when the particulate dust is coarse, when inlet loading is heavy, or when high collection efficiency is not a critical requirement. Since collection efficiencies are low as compared to other types of control devices, mechanical collectors are not usually suitable as the primary means of control when emission regulations are stringent. In this case, one of the devices discussed later in the chapter must be applied.

h. Application as Precleaners. Another common application of cyclones to Army Central Boiler Plants is as a precleaner in solid fuel combustion systems, such as stoker-fired and pulverized coal-burning boilers. In these units, large coarse particles may be generated and a cyclone collector may be installed ahead of an electrostatic precipitator or baghouse to remove these particles. In the case of a stoker/baghouse combination, a mechanical collector is almost mandatory, since hot or burning particles are often carried over them the fuel bed and could ignite the bags. A combination installation is also ideal from a performance standpoint when applied to a precipitator, because the cyclone exhibits increased collection efficiency during high gas flow and dust loading conditions, while the precipitator shows an increase in efficiency during decreased gas flow and dust loading. The two devices

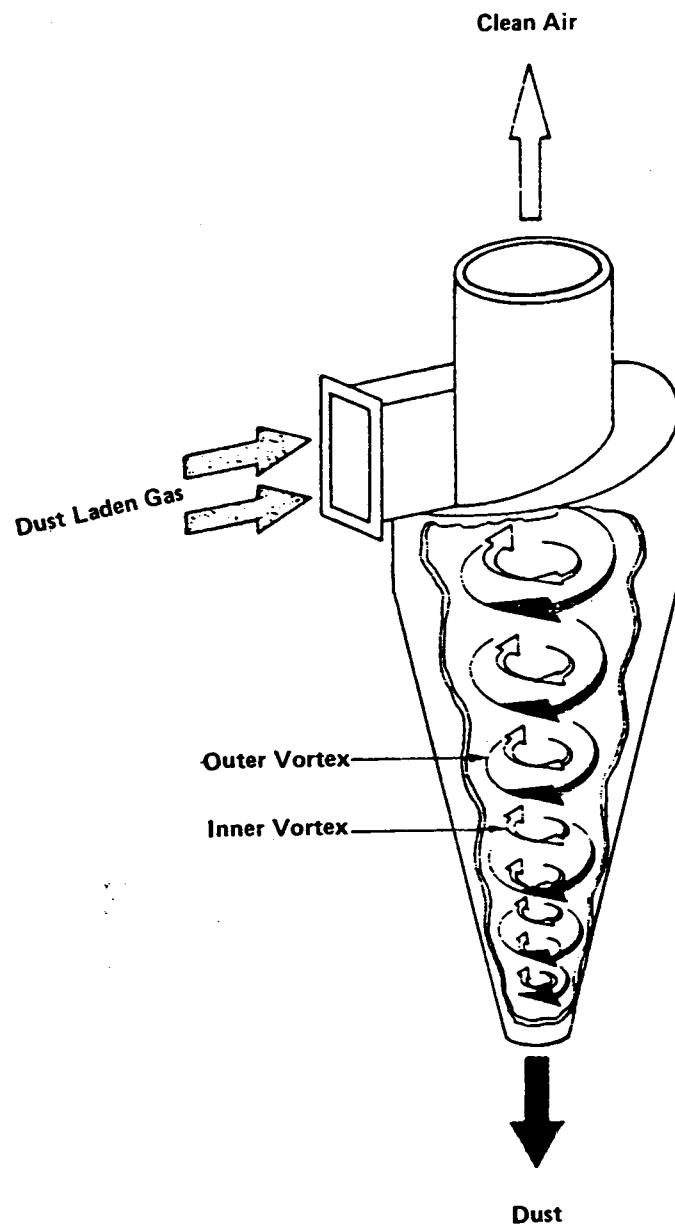
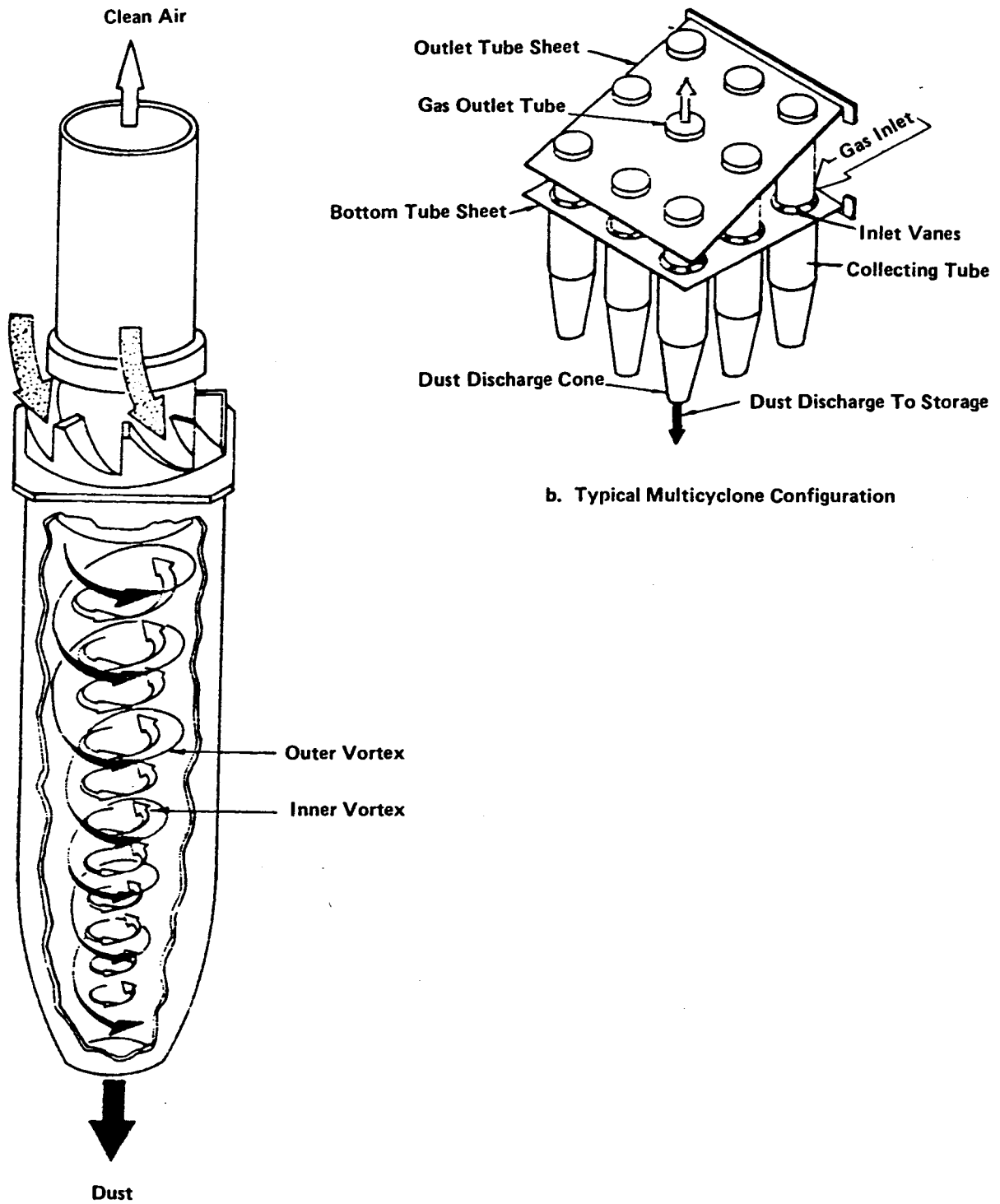


FIGURE 2-97. MEDIUM EFFICIENCY CYCLONE CONFIGURATION



a. Configuration Of Individual Cyclone Tube From Multicyclone

b. Typical Multicyclone Configuration

FIGURE 2-98. MULTI-CYCLONE CONFIGURATION

Table 2-5. Characteristics of Mechanical Dust Collectors

Type	Body Diameter (feet)	Gas Flow (ft ³ /min)	Pressure Drop (in-H ₂ O)	Inlet Velocity (ft/s)	Collection Efficiency (%)	Application	Other
Medium-Efficiency Single Cyclone	4-12	1,000-20,000	.5-2	20-70	50-80	Material Handling	Large headroom requirements. Limited to large, coarse particles; large grain loadings.
High-Efficiency Single Cyclone	Less than 3	100-2,000	2-6	50-70	80-95	Exhaust gas pre-cleaner Industrial boiler particulate control	Smaller space requirement; parallel arrangement; inlet vane flow controls needed continuous dust removal system purge operation.
Multicyclones	.5-1	30,000-100,000	3-6	50-70	90-95	Industrial and utility boiler particulate control	Plenums required. Problems: gas recirculation fouling; continuous dust removal system, flow control.
Wetted Cyclone	Less than 3	100-2,000	2-6	50	90-95	Boiler application (low sulfur fuel) (low temperature).	Water rate 5-15 gal/1,000 ft ³ /min; corrosion-resistant materials.

Note: Cyclone collection efficiency must be evaluated for each specific application, due to the sensitivity of cyclone performance on gas and dust properties and loadings.

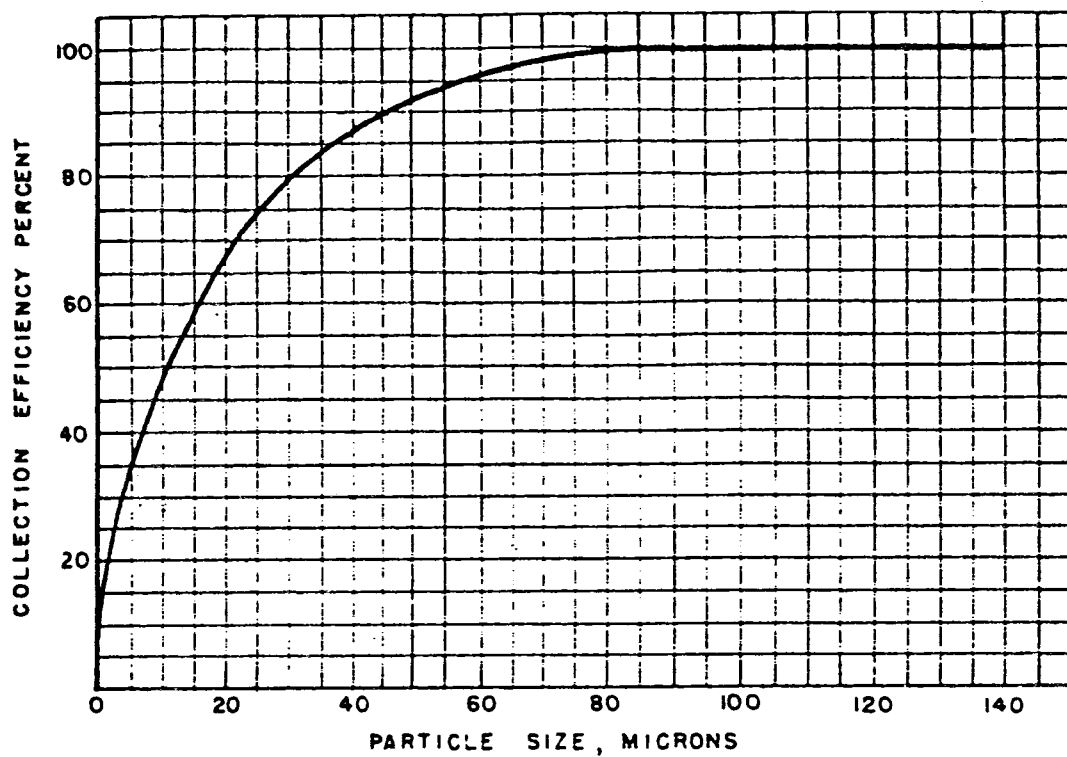


FIGURE 2-99. CYCLONE FRACTIONAL EFFICIENCY CURVE

complement each other to provide good efficiency over a wide range of gas flow and dust loading conditions.

i. Application for Reinjection. Fly ash carried over from a spreader stoker often contains a high percentage of unburned carbon. This constitutes a loss in heating value and, therefore, efficiency. Since the particles are fairly coarse, a medium-efficiency cyclone can collect them effectively with a minimum of added fan horsepower. An additional small fan can then be used to reinject the collected material into the furnace for more complete combustion. This type of cyclone arrangement is typically used ahead of a precipitator or baghouse, which serves as the final collection device.

j. Effect of Firing Modes. The method by which the fuel is fired can have a major effect on the suitability of a mechanical collector for the application. This is due to differences in particle size distribution in the flue gas from the different firing modes. Thus, if the same coal were to be fired in two identical boilers, one using a spreader stoker and the other using a chain grate stoker, the mechanical collector could collect the ash from the spreader stoker fired boiler more efficiently, because it generates coarser fly ash. Table 2-6 illustrates the optimum expected performance of mechanical collectors for particulate removal in various combustion process applications.

TABLE 2-6
REMOVAL EFFICIENCIES OF UNCONTROLLED PARTICULATE
EMISSIONS FROM COMBUSTION PROCESSES

Fuel/Firing Mode Cyclone	Percent Removed	
	Medium Efficiency	
	Multicyclone	
Oil/Steam or mechanical atomizer	30-40	40-50
Coal/spreader stoker	75-85	90-95
Coal/chain grate or underfeed stoker	50-70	85-90
Coal/pulverized	50-70	85-90
Coal/cyclone	30-40	40-50

2-33. FABRIC FILTERS.

Fabric filters, commonly called "baghouses", are used to remove particulate from the flue gas stream. The filters are made of woven or felted high-temperature fabric, such as fiberglass or Teflon. They are normally manufactured in the form of a cylindrical bag, although other configurations are possible. These elements are contained in a metal housing which has gas inlet and outlet connections, a dust storage hopper, and a cleaning mechanism. In operation, dust-laden gas flows through the cloth filters, and the dust is removed from the gas stream as it passes through the filter cloth. The filters are cleaned periodically.

a. Housing Design. For practical reasons, most baghouses

used for boiler flue gas are designed to operate under negative pressure and are located between the last heat trap and the induced-draft fan. Pressurized-type baghouses are very rare. Negative pressure baghouses are constructed with a welded steel, gas-tight housing. It is usually divided into two or more compartments, each having a dust collection hopper beneath it. The hoppers and housing are insulated, and the fan is located on the clean side of the collector.

b. Filter Arrangement. Filters are usually cylindrical but may also be of the flat panel type. The cylindrical types have the advantage of maximizing total cloth area per square foot of floor area, since they can be made very long. They typically have a length-to-diameter ratio of about 30:1. They can be arranged to collect the dust on either the inside or the outside of the cylinder. Flat panel filters consist of large, flat areas of cloth stretched over adjustable frames. Flow direction is usually horizontal. Flat panel filters have the advantages of frames. Flow direction is usually horizontal. Flat panel filters have the advantages of allowing slightly more filter area per cubic foot of collector volume and of allowing the panels to be manually cleaned by brushing if excessive dust buildup occurs.

c. Filter Cleaning Methods. The dust may be removed from the filters by several methods. The most common methods applied are shaking, reverse gas flow, and reverse pulse.

(1) Shaking. A few baghouse designs use a rigid frame and a motor-driven oscillator mechanism to gently shake the dust loose from the bags. However, this is rarely used on modern design units because it increases bag wear and shortens bag life.

(2) Reverse Gas Flow. See figure 2-100. The reverse gas flow cleaning method uses a fan to gently backwash the bags with high-volume, low-pressure, clean flue gas taken from the baghouse outlet. This causes the dust which has accumulated on the bags to drop off into the hoppers. Baghouses of this design use low air-to-cloth ratios and thus require more bags and a larger housing to handle the same gas flow. In addition, a spare compartment must be provided, since the compartments must be taken off-line for cleaning.

(3) Pulse Jet. See figure 2-101. The pulse jet cleaning method utilizes a short blast of high-pressure air (90-100 psig) to blow backwards through the bag and dislodge the dust so that it can drop into the collection hopper. This design has several advantages over the reverse gas flow method and is gradually becoming the dominant design in the industry. Its primary advantages relate to its higher air-to-cloth ratio and subsequently small physical size. This leads to lower initial cost, fewer bags, and lower space requirements. Other advantages are the

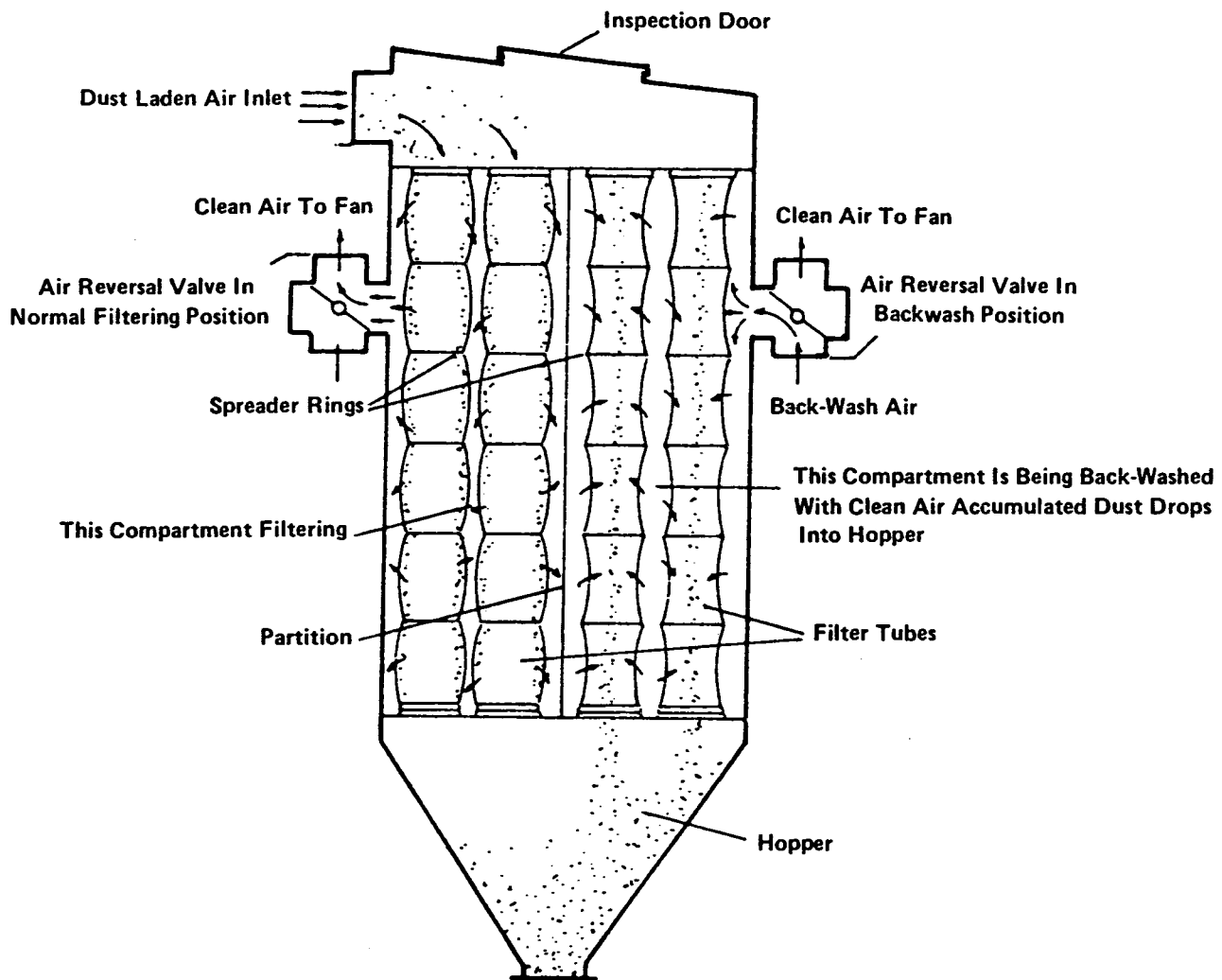


FIGURE 2-100. REVERSE FLOW BAGHOUSE

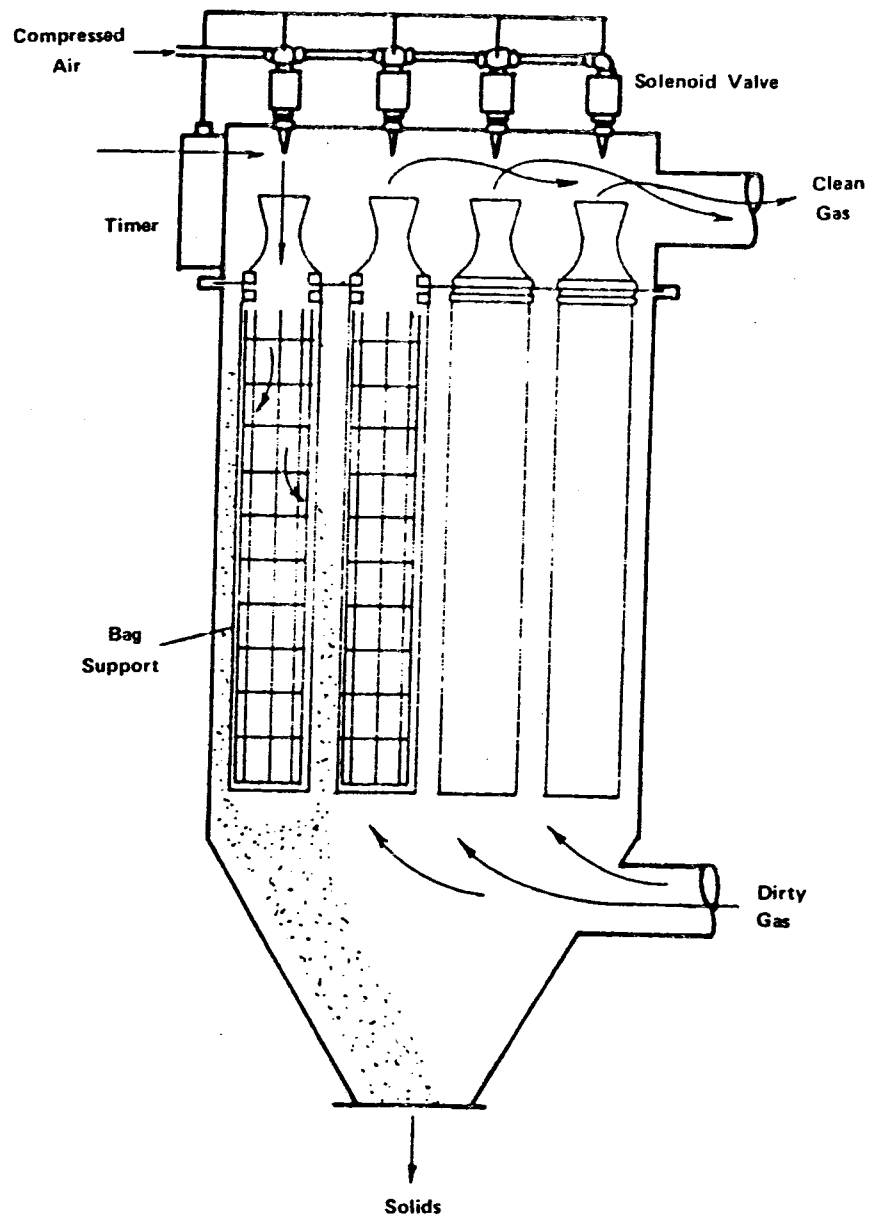


FIGURE 2-101. PULSE JET BAGHOUSE

lower horsepower requirements for generating the cleaning air, fewer moving parts, and the fact that compartments may be cleaned either on- or off-line. Its main disadvantage is that the bags, although fewer in number, must be considerably heavier, and therefore more expensive, in order to withstand the severe cleaning cycles.

d. Energy Requirements. The primary energy requirement of a baghouse is the fan horsepower necessary to move the flue gas through the unit. Resistance to flow arises from the pressure drop across the filter cloth, friction losses through ducts and dampers, and turbulent flow losses. Power is also required to drive the cleaning equipment.

e. Application of Fabric Filters. Properly designed fabric filters may be applied to most coal-fired Army boiler applications, either as part of a new installation or on a retrofit basis. The flue gas temperature into the fabric filter must be maintained above the sulfuric acid dew point but below the maximum permissible filter cloth temperature. Temperature requirements are discussed more fully under OPERATION (Chapter 3). Application to oil-fired boilers is not generally recommended, since unburned oil tends to cause the filters to plug or blind. A bypass around the baghouse is generally utilized for boilers which must burn both coal and oil.

2-34. ELECTROSTATIC PRECIPITATORS.

An electrostatic precipitator (ESP) is a device which removes particles from a gas stream by means of an electric field. The electric field imparts a positive or negative charge to the particle and attracts it to an oppositely charged plate. Provision is also made to remove the dust particles from the collection plates to dust hoppers located below the precipitator. The entire precipitator is enclosed in a metal housing which has a flue gas inlet and outlet and is connected into the boiler flues between the boiler and the stacks. ESPs may be operated under either pressure or suction conditions, with gas flow either horizontal or vertical. Many configurations are possible, depending upon the desired application. The most common applications for Army boilers are discussed below.

a. Electrode Design. Most electrostatic precipitators applied to Army boilers are of the parallel plate design with horizontal gas flow. The plates carry a positive charge and act as the collecting electrode. A large number of negatively charged high voltage discharge electrodes are spaced between the plates. These electrodes impart a negative charge to the particles in the gas stream which are then attracted to the positively charged collection plates. The particles adhere to the plates until they are removed by the cleaning system. This electrode system can be designed in two basic configurations.

(1) **Weighted Wire.** Reference figure 2-102. In the

weighted wire design, both the plates and the wires are suspended from the top and allowed to hang vertically by gravity. Weights are attached to the wire to maintain the proper tension. Precise alignment is necessary so that both sets of electrodes maintain the relationships required for best efficiency. Weighted wire construction has been used for many years, and is well proved and relatively inexpensive. It is a common type of installation for Army boilers, particularly older units.

(2) **Rigid Frame.** Some modern precipitators use rigid frame construction. In this type of construction, both the positive and negative electrodes are rigidly mounted at top and bottom to maintain precise alignment. This is somewhat more expensive, but is advantageous when extremely high collection efficiencies are required. It also reduces maintenance costs by minimizing or eliminating electrode wire breakage.

b. Precipitator Location. Precipitators may be located either in the hot regions of the flue gas stream, where temperatures are above 600° F; or after the last heat trap, where temperatures are between 300 and 350° F. These two locations are termed hot and cold, respectively.

(1) **Hot Precipitators.** Hot precipitators are generally applied to units designed for low sulfur coal because the characteristics of the ash from this type of coal make it difficult to collect in a cold precipitator. Particle resistance to collection decreases at the higher temperature. The ability to remove the particles from the plates and hoppers is also increased at these temperatures. Hot precipitators are more expensive, however, because they must be larger to handle the higher specific volume of the gas stream. Material selection, design for proper expansion, and structural considerations also become more critical at the higher temperatures. Finally, radiation losses from the precipitator housing increase at the higher temperatures, necessitating either more insulation or a reduction in boiler operating efficiency.

(2) **Cold Precipitators.** Cold precipitators are designed to operate at temperatures between 300° F to 350° F. They are smaller in construction and therefore cheaper than hot units for the same boiler size. However, they are not as effective in collecting ash from low sulfur coal. In addition, they may be subject to corrosion due to condensation of sulfuric acid at lower temperatures.

c. Cleaning and Dust Removal. Dust is removed from the electrodes by means of rappers. Rappers can consist of electromagnetic solenoids, motor-driven cams or motor-driven hammers which vibrate or impact upon the tops of the plates and wires. This causes the collected dust to slide down the electrode, eventually reaching the dust collection hopper at the bottom of the unit. Once collected in the hoppers, the dust is removed by the fly ash removal system.

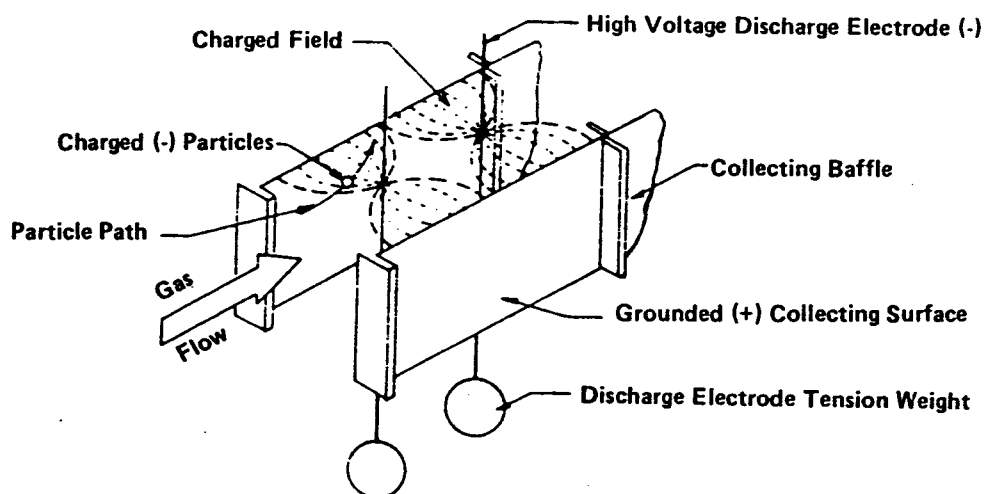


FIGURE 2-102. WEIGHTED WIRE TYPE
ELECTROSTATIC PRECIPITATOR

d. Energy Requirements. The main uses of energy in an electrostatic precipitator are the fan horsepower to move the flue gas through the unit and the power required to maintain the electrostatic field. These two power usages are approximately equal. A typical electrostatic precipitator on a 30,000-lb/hr boiler would require about two to three brake horsepower in fan power consumption and two to three kilowatts to maintain the electrostatic field. The rappers and dust removal systems are other sources of power consumption.

e. Application of Electrostatic Precipitators. Electrostatic precipitators can be designed to function efficiently on almost any boiler, either for a new or retrofit installation, if sufficient physical space exists. However, it is important to have a good knowledge of the fuel analysis which will actually be burned, since this has a major effect upon the design of the precipitator. Once the precipitator has been designed and sized for a given fuel, major inefficiencies and operating problems can result from fuel changes.

2-35. WET SCRUBBERS.

A wet scrubber is a device designed to use a liquid to separate particulate contaminants from a flue gas stream. Although they are rarely used on Army boilers, they have some potential application and advantages over other types of particulate control devices and are thus discussed briefly in this manual. More details can be found in Army Manual TM 5-815. Most wet scrubber applications to Army boilers

would be of the wet approach venturi type (figure 2-103). It is very compact and has the capability to collect particles down to submicron size with about 99 percent efficiency, or even more if necessary. Its principle of operation is somewhat similar to a mechanical collector, but it adds the action of liquid scrubbing to the centrifugal and inertial forces. The incoming gas stream accelerates and atomizes the liquid droplets. These atomized droplets then wash the dust out of the gas stream in the same manner that a severe rainstorm can wash dust out of the atmosphere. Pressure drop through a wet scrubber increases with decreasing particle size and increasing collection efficiency. For a venturi scrubber applied to a coal-fired boiler, pressure drop typically ranges from 20 to 25 in-H₂O. This creates a significant penalty in fan horsepower requirements and is one of the primary reasons that wet scrubbers are seldom applied to Army boilers. Other types of scrubbers can lower this horsepower requirement, but their collection efficiencies are also low. The other major disadvantage of the wet scrubber is its water usage. The cost of pretreating the water and the cost and complexity of treating the waste slurry from the scrubber discharge can be significant. The primary advantages of a wet scrubber are its compact size and its tolerance for extremely high gas temperatures. These two characteristics make it potentially useful for retrofit application where other types of control devices might not be applicable due to efficiency or space requirements.

SECTION VI. AUXILIARY EQUIPMENT

2-36. FEEDWATER HEATERS.

Closed feedwater heaters of the tube and shell type are used to preheat feedwater going to deaerators and hot water boilers as well as for deaerating heating. These closed feedwater heaters can make use of turbine exhaust steam or waste heat generated in the boiler plant to improve overall plant efficiency. Deaerators, deaerating heaters, surge tanks, and condensate return tanks are discussed in chapter 4. Figure 2-104 illustrates a closed tube and shell heat exchanger used for feedwater heating.

2-37. PUMPS AND INJECTORS.

The selection and replacement of pumps require consideration of capacity and pressure requirements, the type and temperature of fluid to be handled, and the type of pump best suited for the job requirements. Performance characteristics vary widely, even among pumps of the same type and capacity. Pumps can be classified into four groups: centrifugal pumps, reciprocating piston pumps, rotary

positive displacement pumps, and jet pumps/injectors. The characteristics of these groups are discussed later.

a. Installation. The selection of a pump for a particular job involves many considerations, but once the pump is selected, successful performance depends upon details of the installation. This is particularly true where the pump must lift the fluid or when the fluid is heated. Greater care must be exercised in design and installation of the suction line than of the pump discharge. A strainer is required to prevent foreign objects from entering and clogging the pump or piping. The maximum suction lift or minimum suction lift or minimum suction head depends to a great extent upon the temperature of the water and the distance of the pump above sea level as noted in table 2-7. The following rules should be observed when installing a suction line to a pump. Disregarding any of the following rules may lead to unsatisfactory operation or complete failure:

(1) The line must be tight. A leak in the discharge line may be annoying, but a leak in the suction line may

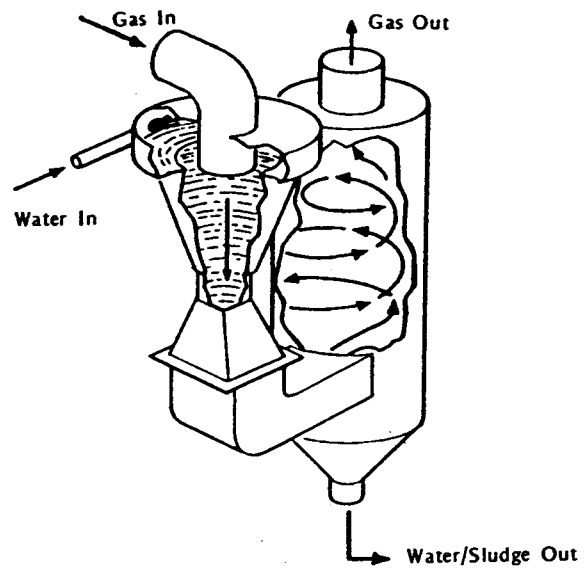


FIGURE 2-103. WET APPROACH VENTURI SCRUBBER

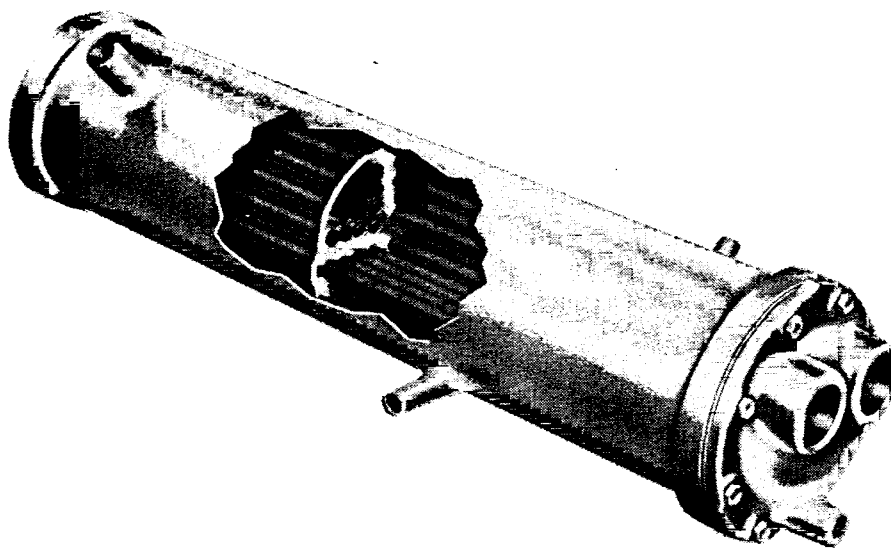


FIGURE 2-104. TUBE AND SHELL HEAT EXCHANGER

lead to inoperation of the pump.

(2) Keep the suction lift, or the vertical distance from the pump to the water supply, as small as possible.

(3) Keep the suction line as short as possible. Keep the number of fittings, such as ells, tees, reducers, and valves to a minimum.

(4) To reduce the losses caused by the pipe friction and high velocity, keep the diameter of the suction line as large as practical.

(5) To prevent formation of air pockets, maintain proper slope on horizontal sections of pipe. Slope the line away from the pump for a suction lift and toward the pump for a suction head. (Reference figure 2-105A). (6) Do not use fittings which permit the formation of air pockets. (reference figure 2-105B). Note: An air chamber is occasionally used on the suction line of a pump to smooth out pressure fluctuations or surges. These must be carefully designed and installed to ensure proper operation.

(7) To keep the line and pump full of water when the pump is idle, install a foot valve on the inlet end of a suction line. A foot valve is a special type of check valve made for this purpose. Very little force is required to operate it, and a strainer is usually incorporated. A foot valve has no value when the pump is located below the source of water supply.

(8) Properly guard all gears, belts, shafts, and other moving parts exposed to hazardous contact, and provide drains from all pump bases.

TABLE 2-7.

PERMISSIBLE MAXIMUM SUCTION LIFTS AND MINIMUM SUCTION HEADS IN FEET FOR VARIOUS TEMPERATURES AND ALTITUDES

	Water Temperature (F)									
Altitude	60	80	100	120	140	160	180	200	210	
At sea level	-22	-17	-13	-8	-4	+0	+5	+10	+12	
2,000' above	-19	-15	-11	-6	-2	+3	+7	+12	+15	
6,000' above	-15	-11	-6	-2	+3	+7	+12	+16	—	
10,000' above	-11	-7	-2	+2	+7	+11	+16	—	—	

NOTE: (-) indicates maximum suction lift, or distance of pump above water.

(+) indicates suction head, or distance of pump below water.

b. Centrifugal Pumps. Centrifugal pumps use a rotating impeller to give velocity and pressure to the fluid. This type of pump is widely used in boiler feed and condensate pumping applications. Figure 2-106 illustrates a horizontal split case type of centrifugal pump. Centrifugal pumps are available in many configurations, including single and double suction, single and double volute, multistage, and vertical. Although these pumps look different, they all have basically the same components and operate similarly. They are compact, of simple construction, discharge at a uniform rate of flow and pressure, contain no valves or pistons, operate at a high speed, and can handle dirty water. They have two major disadvantages: comparatively low

efficiency, and inability to discharge air or vapor. However, their advantages more than offset the lower efficiency. The inability to discharge air can be overcome by proper installation and operating practices.

(1) **Construction.** The pump shown in figure 2-106 consists of the rotating element called an impeller, the casing, the shaft, and the parts used for sealing the pump against leakage.

(a) The impeller consists of two disks separated by a number of vanes which form passages for the water and are connected to the hub. This impeller may be of cast iron, bronze, steel, or other alloys, depending upon the fluid to be handled. Its diameter depends on its operating speed and the difference between suction and discharge pressures. The pressure difference is usually called the pump head and is measured in feet. An impeller may be either single or double suction. The one shown is the double suction type, in which water enters from both sides.

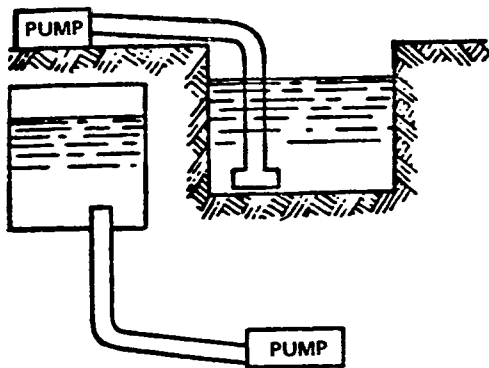
(b) The casing is split on the horizontal center line and contains the inlet and outlet passages. Inlet and outlet connections are usually in the bottom half of the casing, permitting disassembly and repair of the pump without disturbing pipe connections or pump alignment. The casing guides the water from the inlet connection to the impeller and from the impeller to the discharge connection. The casing, although usually made of cast iron, can be made of other materials if necessary to handle special fluids.

(c) The shaft supports and drives the impeller and is, in turn, supported by the bearings. Babbit-type bearings are used in the pump shown in figure 2-106, though many pumps use ball bearings.

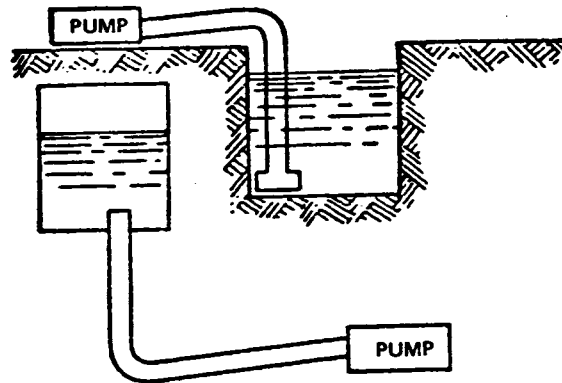
(d) The impeller is held firmly by shaft sleeves which also help to seal against leakage of air into the pump. Sleeves are held in place by two nuts, one of which has a right-hand thread and the other a left-hand thread. Packing is sometimes provided between these nuts and the sleeves to ensure a tight seal. Stuffing boxes are provided where the shaft passes through the casing. Stuffing boxes are filled with packing held in place by packing glands. A brass or bronze lantern ring is often inserted between two adjacent rings of packing to provide a channel for the sealing water. The sealing water lubricates and cools the packing and shaft sleeve and helps seal against air leakage into the pump. It may be supplied directly from the pump, as shown, or from an outside source. The casing has renewable rings to reduce leakage from the discharge to the inlet side of the impeller. Renewable wear rings are occasionally installed on the impeller.

(2) Operation

(a) When the pump is operating, the impeller rotates at high speed, drawing water into its center, near the shaft. The resultant centrifugal force imparts energy to the water,

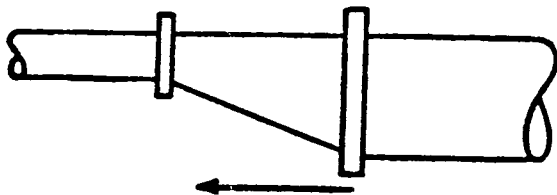


Good Design

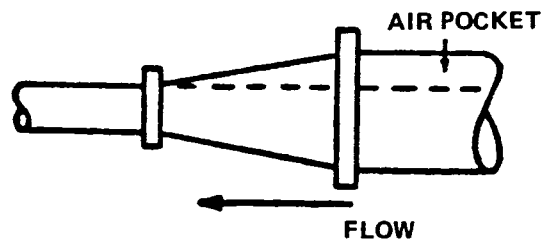


Poor Design

FIGURE 2-105A. MAINTAIN PROPER SLOPE TO SUCTION LINE



Good Design



Poor Design

FIGURE 2-105B. SUCTION LINE INSTALLATION

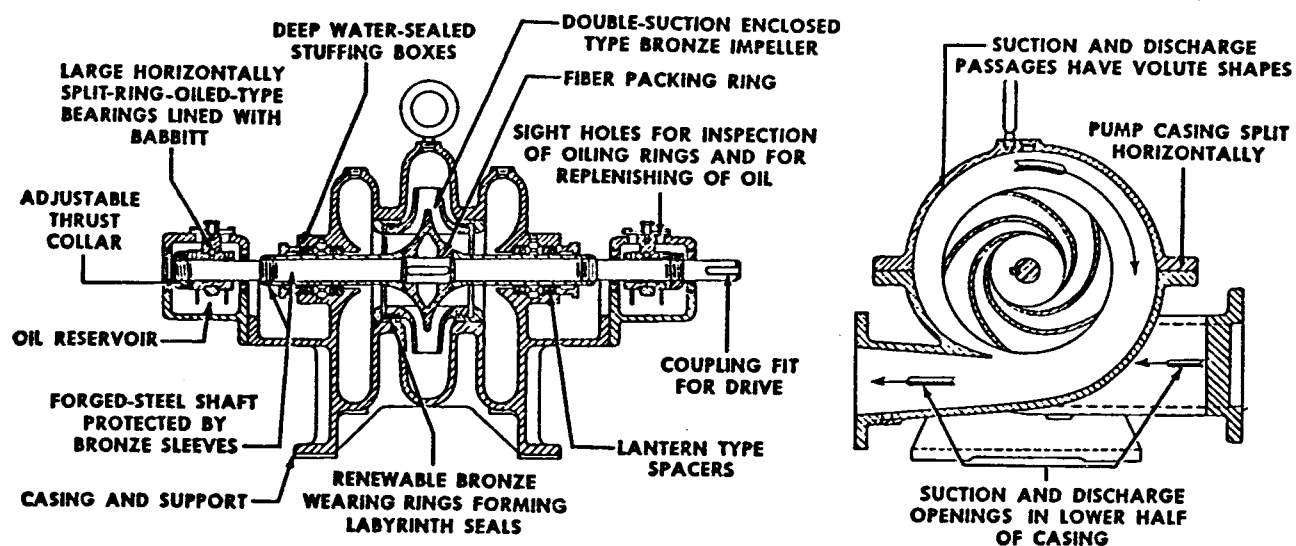


FIGURE 2-106. CENTRIFUGAL PUMP

which is forced outward. As this occurs, the partial vacuum produced at the inlet draws additional water. The casing must transform the velocity of water leaving the impeller into pressure with minimum loss. This is done in the pump shown by making the casing in the form of a spiral, called a volute, and gradually increasing its cross-sectional area from its beginning to the pump discharge. The pump shown is called a single-stage pump because the water passes through only one impeller. Multistage pumps are used when it is necessary to operate against higher heads. In a multistage pump the water travels through successive impellers or stages until it has reached the desired head.

(b) The output of a centrifugal pump can be controlled by regulating the pump speed, providing a controlled recirculation line, or throttling the discharge. The recirculation line, or bypass, consists of a valved line between the pump discharge and suction. The output of the pump is decreased by opening this valve and recirculating the water through the pump. Throttling the discharge increases the pressure at the pump outlet, causing some of the fluid to stop and remain in the pump casing. Any of these control methods can be manual or automatic. A centrifugal pump must be equipped with a check valve on the discharge side to prevent backflow of water when the pump is inoperative. Centrifugal pumps are designed to deliver a given quantity of fluid against a specified discharge pressure or head. Every centrifugal pump has a maximum or shutoff head, above which it is unable to deliver any fluid. This fact should be taken into consideration when an increase in delivery pressure is contemplated. The shutoff head can sometimes be increased by substitution of a larger impeller, although a larger motor may also be required.

c. Reciprocating Piston Pumps. The direct-acting, steam-driven duplex pump is widely used because of its low initial cost, low maintenance, simple operation, and positive action. Simplex pumps are rarely used because of the wide fluctuation in fluid pressure at the pump discharge.

(1) A horizontal duplex piston pump is shown in figure 2-107. This type of pump consists of two single-cylinder pumps mounted side by side. The piston rod of one pump operates the steam valve of the other through a system of bell cranks, rocker arms, or links. The pistons move alternately so that the resultant discharge of water is essentially continuous. Steam is admitted for the full stroke and is not used expansively, resulting in high steam consumption for the amount of water handled. Each cylinder has two ports in each end, one of which admits steam while the other discharges it. This minimizes the required valve travel but leaves sufficient bearing surface between the steam ports and the main exhaust port to prevent steam leakage from one to the other. The steam

which is trapped in the cylinder when the exhaust stroke nears completion provides a cushion to prevent the piston from striking the cylinder heads. Some pumps also have small hand-operated valves on the side of the steam chest to regulate the amount of cushioning by controlling the escape of the steam from the cylinder. Maximum cushioning is desired with the pump operating at high speeds, and is obtained by closing the hand valve.

(2) The valves of a duplex pump do not overlap the edges of the ports with the valve in its midposition. The valves are held to their seats by the pressure differential acting on the two sides of the valve. Figure 2-108 shows the relative position of the working parts when pump and valve are in midposition. The illustrations indicate that the valves are not fastened rigidly to the stem and that there is lost motion between the valve and the stem. This lost motion is provided to force the pump to take a full stroke; otherwise, it would make only about a quarter stroke. The typical operations of the pump are also due to this lost motion. When one piston has completed its stroke, it pauses and goes into reverse only after the second piston has reached the end of its stroke and moved its valve. One piston is always in position to move so that the pump goes into operation as soon as the steam valve is opened.

d. Rotary Positive Displacement Pumps. Rotary positive displacement pumps use gears, screws, or sliding vanes to move a volume of fluid through the pump. Rotary positive displacement pumps are most commonly used in Army boiler plants to pump fuel oil. Very close tolerances are maintained between the pump internals to minimize slippage of fluid. Slippage in a positive displacement pump may be less than 0.5%, while slippage of 50 percent or more is common in centrifugal pumps. These pumps can thus operate at high efficiencies and pressures. Rotary positive displacement pumps should be equipped with relief valves to protect against overpressurization. While centrifugal pumps may be controlled by throttled flow, rotary positive displacement pumps are controlled by recirculating a portion of the pumped fluid back to the tank or the pump suction.

e. Jet Pumps/Injectors. An injector is a jet pump used to feed water into a boiler, where its high thermal efficiency justifies its use. Most of the heat, in the form of steam, used to operate the pump is returned to the boiler with the water. The injector is convenient, cheap, compact, efficient, and has no moving parts. It delivers warm water into the boiler without preheating, and has no exhaust to dispose of. It cannot be used to pump hot water and can handle a maximum water temperature of about 140 F. Excessive preheating of feedwater passing through the injector often causes impurities to drop into the tubes, scaling them so heavily that the injector fails to function.

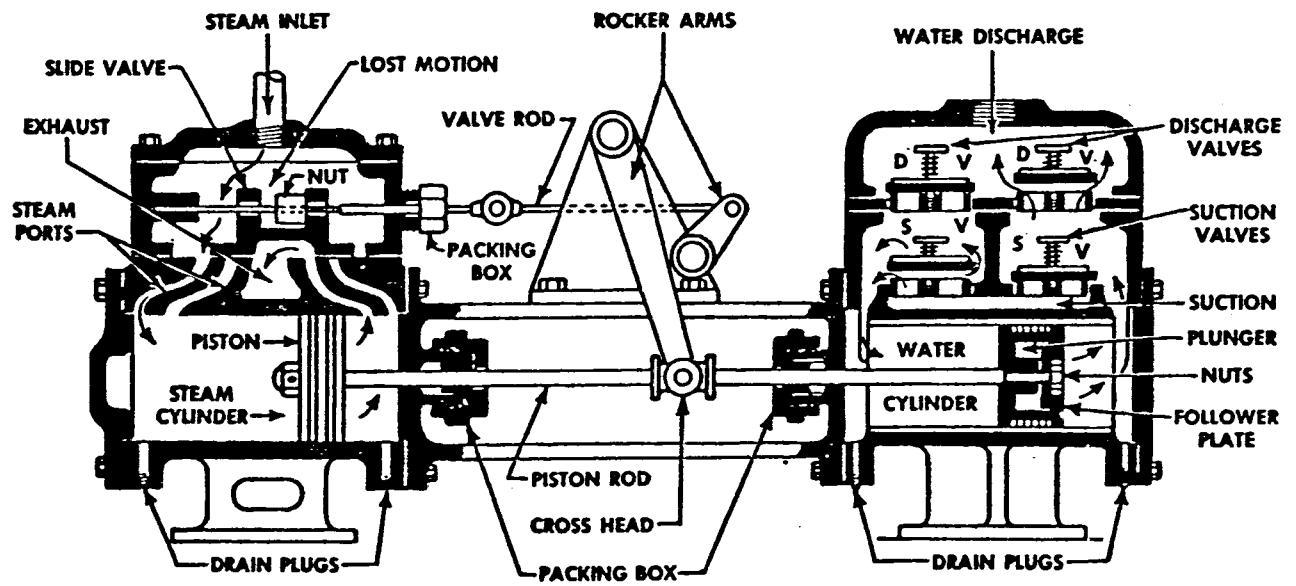


FIGURE 2-107. RECIPROCATING PISTON PUMP

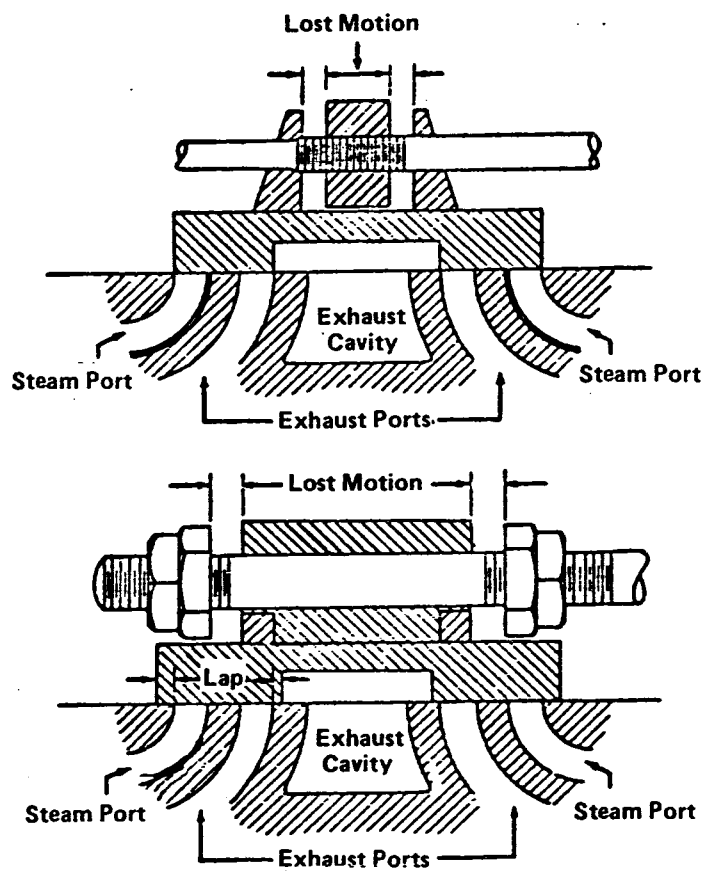


FIGURE 2-108. TWO METHODS OF PROVIDING
LOST MOTION

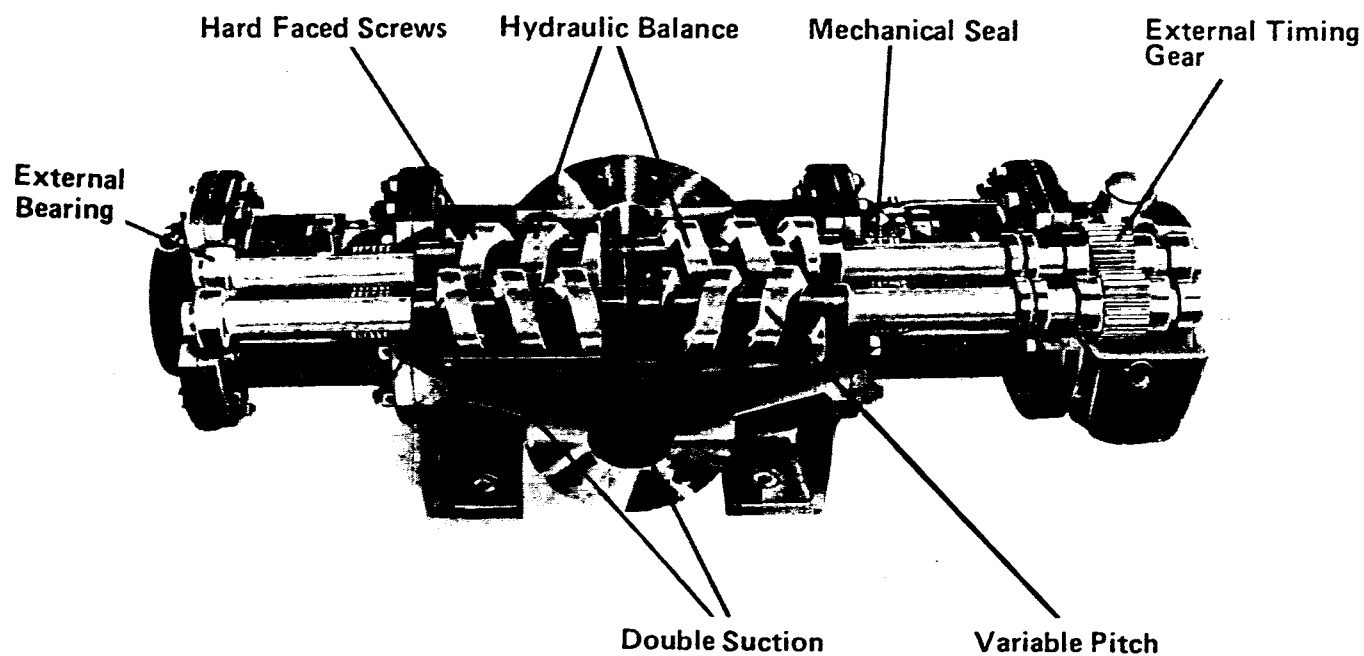


FIGURE 2-109A. ROTARY SCREW PUMP

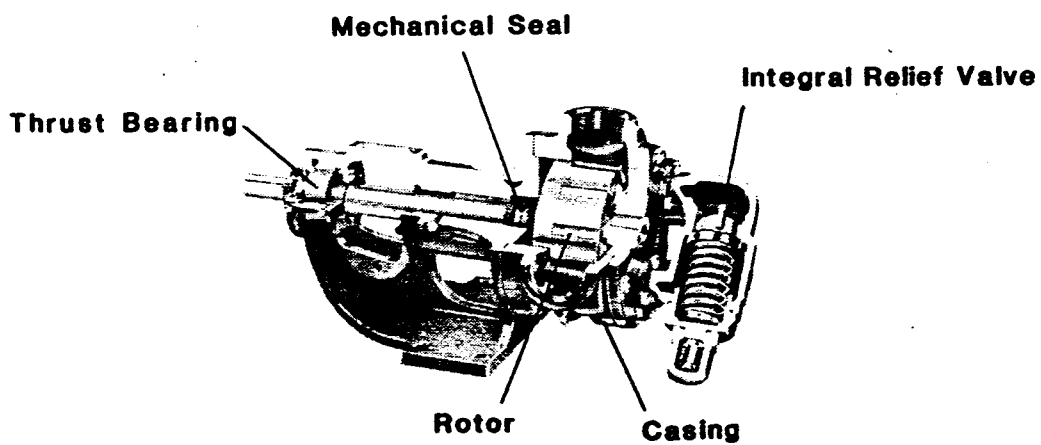


FIGURE 2-109B. ROTARY GEAR PUMP

The essential parts of an injector are the steam tube, combining and delivery tubes, and the necessary casing to guide the water to and from these tubes. Reference figure 2-110. The shape of the steam tube is designed in the shape of a venturi to increase the velocity of the steam passing through the tube. As a result of this high velocity, air is partially evacuated from the inlet line, causing the water to rise until it contacts the steam at the entrance of the combining tube. The steam is condensed and imparts considerable velocity to the water. The condensing steam reduces its volume and thus maintains the vacuum. The combining tube further increases the velocity of the moving mass of water, enabling it to cross the opening to the delivery tube. The water velocity opens a check valve and water enters the boiler against the boiler pressure. An overflow is provided to remove water when the injector is started. No water should appear at the overflow if the injector is operating properly. Injectors can be hand-starting, automatic, single-tube, or double-tube. An automatic injector will resume its flow after an interruption without any attention from the operator. The injector operates satisfactorily under a constant load and pressure but becomes unreliable when operating with fluctuating pressure. Due to this fact and to the low temperature limitations, injectors are rarely used on modern installations. Injector failures are rarely used on modern installations. Injector failures are most often caused by excessive suction lift, hot water, clogged strainer or suction line, and fluctuating pressures.

f. Boiler Feed Pumps. The boiler feed pump is probably the single most important auxiliary in the boiler plant. It must be operated continuously while the boiler is in operation, and at a rate of discharge equal to the rating of the boiler. The Code requires the boiler to have two methods of feeding water, to ensure that an adequate supply is available at all times. Reciprocating and jet pumps can be used for this purpose, but centrifugal pumps are most commonly used in modern stationary practice. Centrifugal pumps have the advantages of small size, high speed, low chance of boiler water contamination with oil, and continuous steady flow.

(1) Reciprocating Pump Application. The area of the steam cylinder of a reciprocating pump ranges from two to three times that of the water piston or plunger to allow for friction losses and to permit the pump operation at reduced steam pressures. A boiler feed pump is required to pump against a total head ranging from 1.1 to 1.5 times the boiler pressure. A reciprocating pump must be sized to provide the desired water discharge capacity with the pump operating at approximately one-half the maximum stroke rate. This allows for pump wear and provides a margin in an emergency, such as low water or ruptured tubes. Reciprocating pumps of the direct-acting duplex type

are sometimes used for small capacities and moderate pressures. They consume approximately 5% of the steam produced by the boiler, but since the exhaust is utilized to heat the feedwater, the net heat consumed by the pump can be less than 1%.

(2) Centrifugal Pump Application. Centrifugal pumps for boiler-feed applications must be sized to develop enough head and capacity to feed the boiler under all conditions. A centrifugal pump may be driven by a steam turbine or a variable- or constant-speed motor. The method used to control output depends primarily on the type of drive used. Any centrifugal pump used to pump hot water must be provided with an adequate flow of water at all times. Centrifugal pumps quickly become steam-bound and stop pumping under certain conditions, and may be damaged if permitted to operate under those conditions for any length of time.

g. Condensate Pumps. Reciprocating, positive-displacement rotary, and centrifugal pumps are used for this service. Heating systems generally use an automatic float-operated centrifugal pump. The condensate drains to a return tank or reservoir, and a float operates a motor switch which starts and stops the centrifugal pump. In one arrangement, the motor is on top of the tank and the pump is at the bottom. In another arrangement, the pump and motor are mounted outside and below the return tank.

h. Vacuum Pumps. Reciprocating, jet, and positive-displacement rotary-type pumps may be used for vacuum service. A centrifugal pump can be used to supply water to the jet, which actually maintains the vacuum. Reciprocating pumps, arranged to remove both condensate and air at the same time, are called wet vacuum pumps. This is a common arrangement and is used with small condensing turbines or engines. Smaller clearances in the water end characterize pumps used for this service. A pump which removes only air is known as a dry vacuum pump. The vacuum pump in a vacuum-return heating system must handle both air and water. One method of doing this is to use a pump with two impellers mounted on a shaft. One impeller handles the water and the other the air. The condensate flows into the receiver and enters the pump. An automatic control actuated by the water level and the pressure in the receiver (which is below atmospheric) starts and stops the pump as required. This arrangement can maintain a vacuum of 10 to 18 inches of mercury in a system which is reasonably free from leaks.

2-38. FORCED DRAFT FANS.

Forced draft (FD) fans are applied to push the combustion air through the burner into the furnace. If an induced draft fan is not supplied, the forced draft fans must also

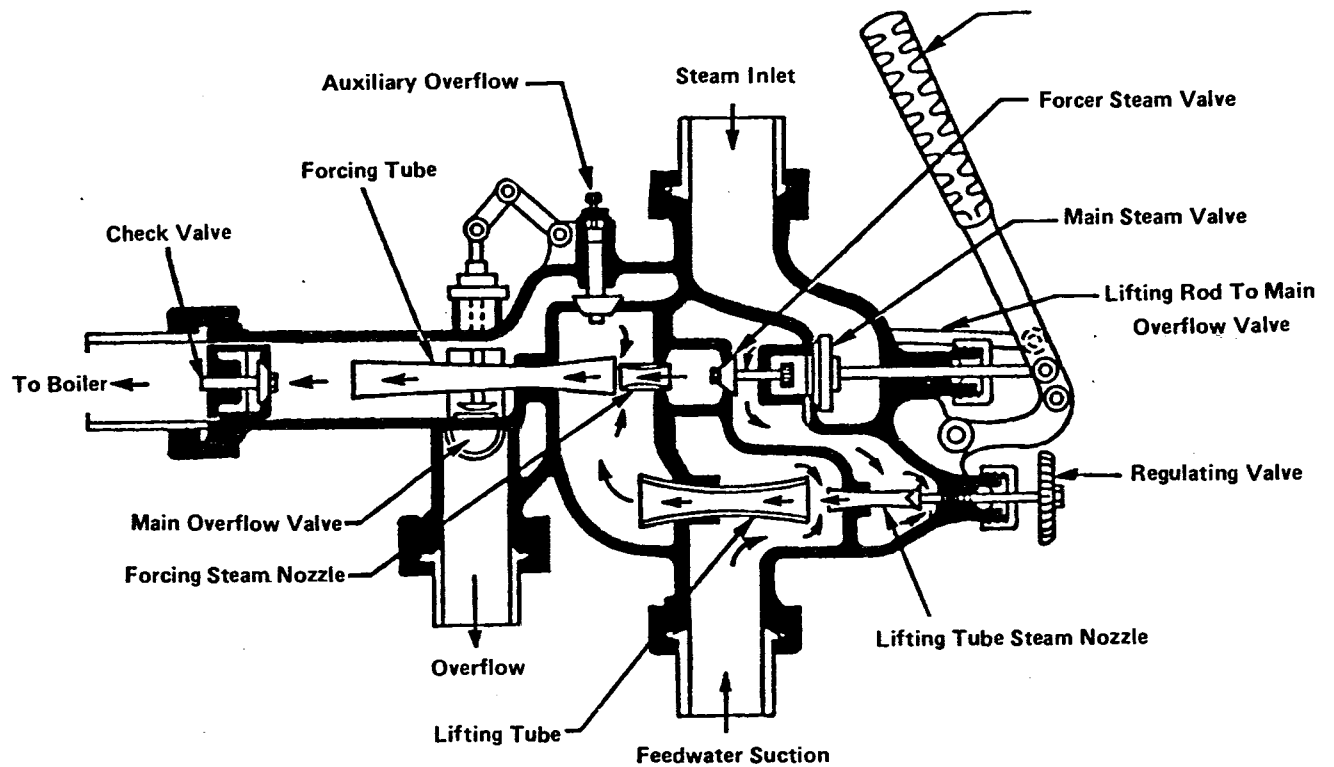


FIGURE 2-110. STEAM INJECTOR

push the products of combustion through the boiler to the stack. Both centrifugal and axial fans are used, with centrifugal units being more common. Centrifugal fans include the following blade designs: radial, forward curved, forward curved/backward inclined, backward inclined, and airfoil/backward inclined. Backward inclined and airfoil/backward inclined fans are most commonly used for forced draft fan service because of their high efficiency, stable operation, and non-overloading horsepower characteristics. Forced draft fans are required to operate over a load range of approximately 25 to 100 percent of capacity. This is accomplished primarily by the use of dampers. Three types of dampers are used: inlet dampers, parallel blade outlet dampers, and opposed blade outlet dampers. Figures 2-111 illustrates a forced draft fan equipped with inlet vane dampers. Figure 2-112 illustrates a typical parallel blade outlet damper. Inlet givane dampers control air flow through the fan by pre-spinning the entering air. Each position of an inlet vane damper in effect creates a new fan and horsepower curve, as shown in figure 2-113. This results in improved control range and horsepower savings over outlet damper applications which control by creating a static pressure on the fan. The increased static pressure reduces flow and causes the operating point to move back up the fan curve (reference figure 2-114). Opposed blade outlet dampers provide a greater control range than parallel blade outlet dampers, which operate best in the 70 to 100 percent capacity range.

2-39. INDUCED DRAFT FANS.

Induced draft (ID) fans are used to exhaust the products of combustion from the boiler. Maintaining balanced draft conditions in the furnace improves boiler operation and provides energy to move the flue gases at the velocities needed for good heat transfer. Induced draft fans are subjected to more severe service conditions than forced draft fans, because they must handle larger volumes of gas at high temperatures and containing ash particles. The physical characteristics of ID fans must therefore be different from those of forced draft fans. Airfoil blades are not recommended for ID fan service. Backward inclined fans are acceptable for non-abrasive gas service, while radial or radial tip blades and forward curved/backward inclined fans are recommended for abrasive service. The higher temperature of gases handled by the ID fan sometimes makes it necessary to use water-cooled bearings to prevent overheating. Inlet damper controls or variable speed drives are used to control induced draft fan capacity.

2-40. STACKS. FLUES. AND DUCTS.

Stacks or chimneys are necessary to discharge the products of combustion at a sufficiently high elevation to prevent

nuisance due to low-flying smoke, soot, and ash. A certain amount of draft is also required to conduct the flue gases through the furnace, boiler, tubes, economizers, air heaters, and dust collectors, and the stack can help to produce part of this draft. The height of the stack necessary to meet the first requirement is often enough to also produce the draft necessary to meet the second requirement. The amount of draft available from a stack depends on the height and diameter of the stack, the amount of flue gas flowing through it, the elevation above sea level, and the difference between temperature of the outside air and average temperature of gases inside the stack. Excessive stack temperatures are undesirable, because they represent a heat loss and efficiency reduction.

a. Stack Construction. Stacks are built of steel plate, masonry, and reinforced concrete. Caged ladders should be installed. All stack guys should be kept clear of walkways and roads and, where subject to hazardous contact, should be properly guarded. Stacks are provided with means of cleaning ash, soot, or water from their base, the means depending mainly on the size of the stack.

(1) **Steel.** The advantages of steel stacks over masonry or reinforced concrete are reduced construction time, low weight, smaller wind surface, and lower initial cost. Major disadvantages are higher maintenance cost and shorter life. Steel stacks may be either self-supporting or guyed, single-wall or double-wall construction, and lined or unlined. Unlined guyed stacks usually are used on smaller installations. This type of stack can be supported by the boiler smoke box, the building structure, or a separate foundation. Two sets of four guy wires each are usually used to hold the stack erect. Steel stacks over 72 inches in diameter are normally self-supporting. They are typically lined with refractory or insulation to protect the metal from the corrosive attack of the flue gases and to improve the performance of the stack by minimizing cooling of flue gases. The self-supporting stack is usually mounted on its own foundation or on the building structure framework. Stub and venturi stacks are typically of steel construction and usually extend no more than about 20 feet above the boiler. When these stacks are used they contribute little to the draft requirements, which must be then supplied entirely by forced-and/or induced-draft fans.

(2) **Brick.** The modern brick chimney built of special radial brick or block is very satisfactory, its major disadvantage being its higher cost. This type of stack is normally lined with fire brick for about one-fifth of its height and must be protected from lightning.

b. Flues and Ducts. Flues are used to interconnect boiler outlets, economizers, air heaters, and stacks. Ducts are used to interconnect forced-draft fans, air heaters, and windboxes or combustion air plenums. Flues and ducts are usually made of steel. Expansion joints are provided to

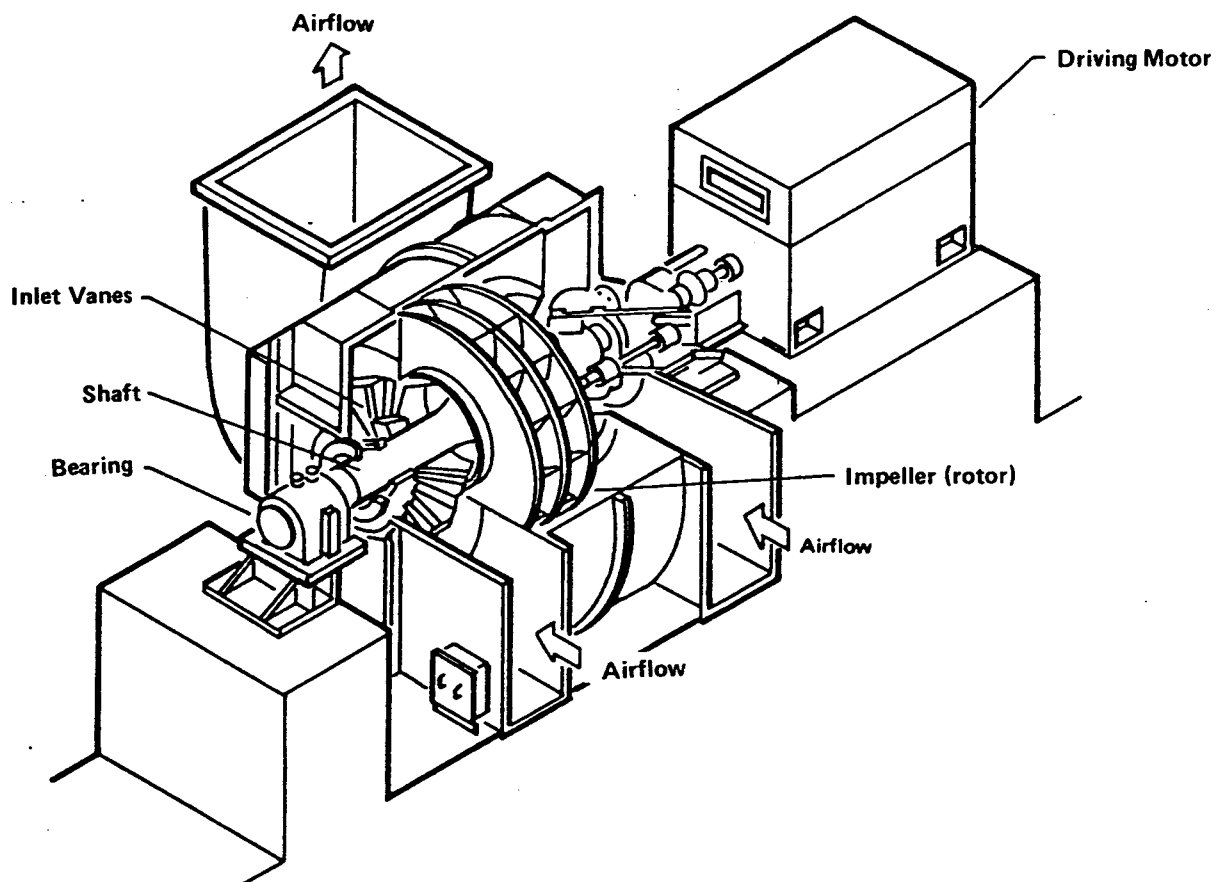


FIGURE 2-111. FORCED DRAFT FAN WITH INLET DAMPER

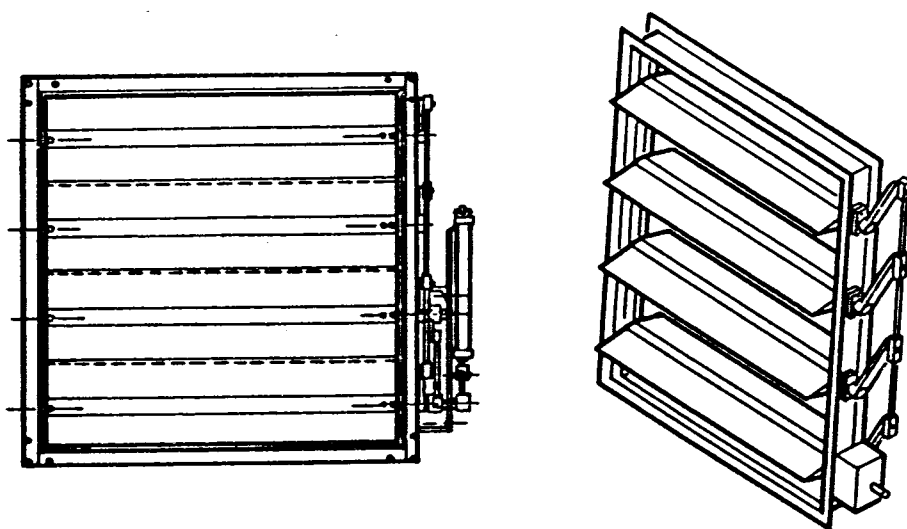


FIGURE 2-112. TYPICAL OUTLET FAN DAMPERS

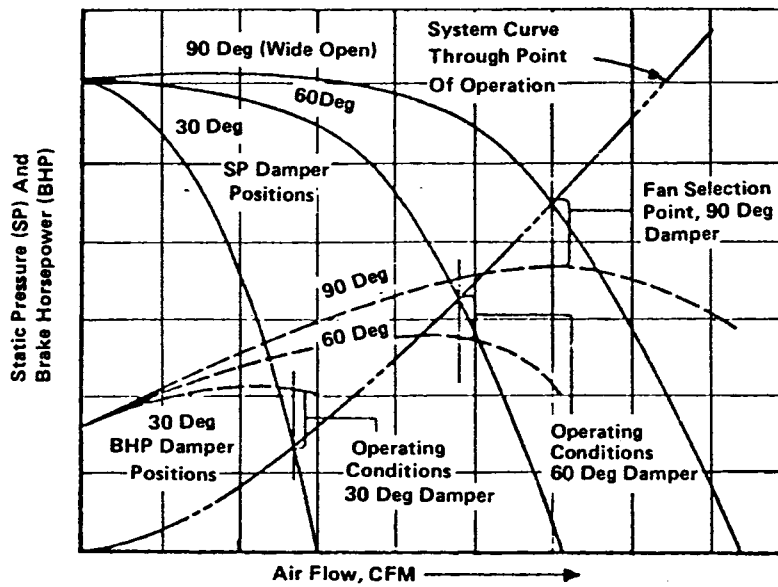


FIGURE 2-113. FAN CURVES FOR DIFFERENT INLET VANE POSITIONS

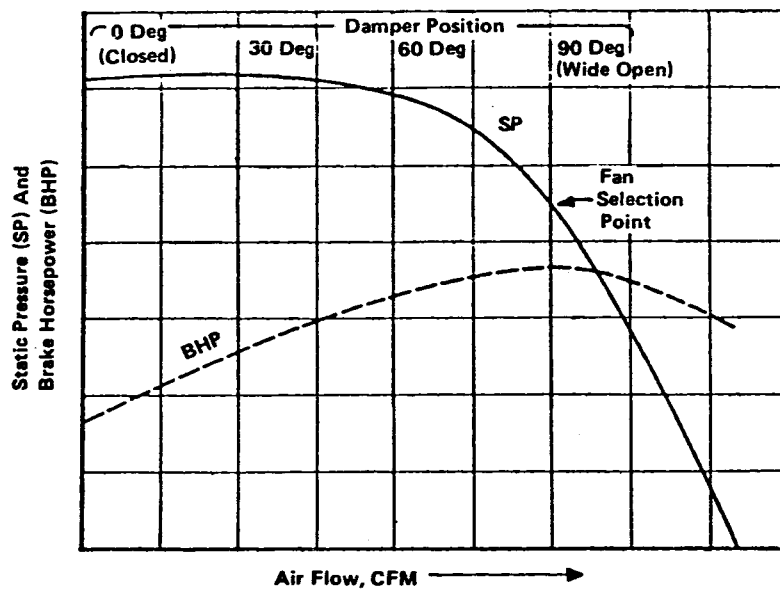


FIGURE 2-114. FAN CURVE FOR FAN WITH OUTLET DAMPER

allow for expansion and contraction. All flues or ducts carrying heated air or gases should be insulated to minimize radiation losses. Outside insulation is preferred for its maintainability. Flues and ducts are designed to be as short as possible, free from sharp bends or abrupt changes in cross-sectional area, and of adequate cross-sectional area to minimize draft loss at the design flow rates.

2-41. STEAM TURBINES.

The reciprocating steam engine with its need for oil lubrication and the resulting contaminated steam has been replaced by steam turbines and electric motors. Steam turbine driven boiler plant auxiliaries are generally economical only if the exhaust steam can be used for feedwater or other heating applications. The steam turbine uses a rotating wheel, with buckets or blades uniformly spaced around its circumference to transform the heat energy of steam into mechanical energy or work. Steam, expanding through a nozzle, is directed against these buckets and causes the wheel to turn. Various types of steam turbines differ in the construction and arrangement of the nozzles, steam passages, and buckets. The steam turbine is essentially a high-speed machine; it is best used with direct connection to electric generators, pumps and fans, and with geared connection to low-speed machinery. The common non-condensing turbine operates at an efficiency of only 20 percent. Only special circumstances, such as the necessity for oil-free exhaust steam, can justify the use of a small turbine for any purposes other than standby or emergency. Figure 2-115 shows a single-stage impulse non-condensing steam turbine.

2-42. ELECTRIC MOTORS.

Electric motors can be grouped into three general classes based on power source. These classes are direct current, single-phase alternative current (AC), and three-phase AC. Three-phase motors are available in squirrel cage, synchronous, and wound rotor. The squirrel-cage motor has become dominant because of its low cost, high reliability, high efficiency over a wide load range, and high starting torque, and it is estimated that 90% of all electric motor energy is consumed by three-phase squirrel motors. Not all squirrel-cage motors perform equally, however. When the need to replace or install a new motor exists, modern higher efficiency and higher power factor designs should be considered. Economic analysis usually justifies the slightly higher initial cost of high-efficiency motors.

2-43. ELECTRICAL EQUIPMENT.

Electrical equipment used in central plants includes motors, motor starters, controls, circuit breakers, switchgear, transformers, fire protection, lighting, conduit, and wiring.

Operation of these devices involves the use of voltages which are dangerous to life. Operating personnel must observe safety regulations found in Army Manual TM 5-682. Additional information on electrical equipment can be found in Army Manuals TM 5-680G, TM 5-683, TM 5-684, and TM 5-687.

2-44. VARIABLE SPEED DRIVES.

Electrical, mechanical, and fluid variable speed drives are available. Electrical drives include multiple speed motors, variable frequency controls, and variable voltage controls. The development of solid state components has allowed the design of variable frequency controls which can operate at high efficiency over a wide load range. Mechanical variable speed drives include belts with adjustable pulleys, gear reducers, and geared transmission. Fluid drives include a variety of hydraulic couplings.

2-45. AIR COMPRESSORS.

Three basic types of air compressors are available: reciprocating, rotary, and centrifugal. Air compressors may be further classified as oil-free or lubricated. Air compressors used in Army installations are comparatively small units, with final discharge pressures of approximate 100 psi. They are typically of rotary screw or single- or two-stage reciprocating design. These two types are discussed below. TM 5-810-4 may be referenced for additional information on compressed air systems.

a. Compressor Types

(1) **Reciprocating.** The reciprocating compressor is a piston-type, positive displacement machine. Air volumes can range up to approximately 6,000 CFM. Two-stage compressors are frequently used, because they require less power to compress a given quantity of air than do single-stage machines. Cylinders and intercoolers of two-stage machines may be cooled by either air or water. The need for shielding or baffling structures for noise attenuation requires investigation when reciprocating compressors are to be used.

(2) **Rotary Screw.** Rotary screw compressors are also classified as positive displacement machines. They operate by passing the inlet air through an inlet valve, and then compressing it through the action of two helical screws rotating against one another. Air volumes can range as high as 3,000 CFM but are more typically in the 100 to 150 CFM. Packaged units are readily available in sizes up to 500 CFM which incorporate all the necessary filters, coalescers and coolers into a single, factory designed and assembled unit. Liquid sealed rotary screw-type units are available up to about 300 CFM and can provide oil-free air. This type of compressor is recommended in food processing or health care facilities but is not often used

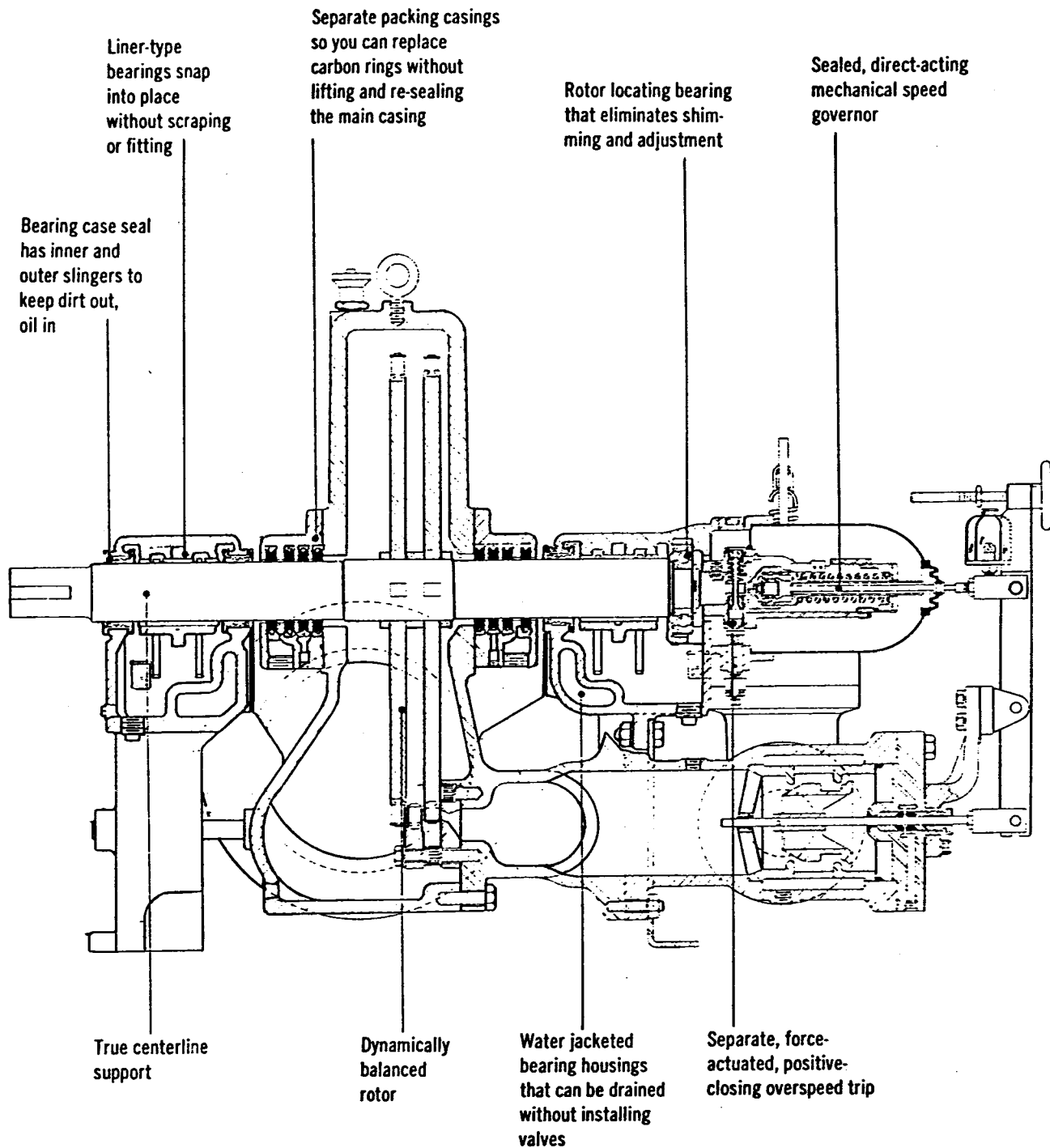


FIGURE 2-115. SINGLE-STAGE IMPULSE
NON-CONDENSING TURBINE

in boiler plants. It is more common to provide oil-free air to boiler plants by means of filters and separators in combination with one of the compressor types discussed above.

b. Capacity of Air Compressors. Total air requirement should be based not upon the total of individual maximum requirements but upon the sum of average air consumption of air-operated devices. Compressor capacity should be based upon the calculation procedure explained in TM 5-810-4.

c. Aftercoolers. In the process of compressing air, approximately 80 percent of the energy delivered by the electric motor becomes heat energy stored in the compressed air at elevated temperature. Aftercoolers are required to cool the air to a more usable temperature. An aftercooler is a heat exchanger which is sized to cool the air below the dew point so as to allow water and oil vapors to condense. A moisture separator is attached to remove the condensed vapors. The aftercooler is normally cooled with water, but it may also use air as its heat exchanger medium.

d. Air Dryers. Some compressed air applications require moisture removal in addition to that provided by the aftercooler. Such applications in the boiler plant include pneumatic tools, operation of pneumatic drives on dampers or valves, and instrument air. For these applications, a supplemental dryer is required. Three basic categories exist: refrigeration dryers, regenerative dryers, and deliquescent dryers. Regenerative dryers are the type usually used in boiler plants, and are discussed here. Information on the other types may be obtained from manufacturers or from TM 5-810-4. Regenerative dryers are further broken down into three types: heatless desiccant, heat regenerative, and low temperature regenerative.

(1) Heatless Desiccant Dryers. Heatless desiccant regeneration passes a quantity of dried (purge) air through the offstream bed. No external heat is applied. This type should be selected with a field-adjustable purge control so that the purge rate (and therefore the pressure dew point) can be adjusted to accommodate seasonal variations in ambient temperature, thereby reducing operating costs. Heatless dryers are capable of providing minus 150 F pressure dew point. Maintenance costs are low, since there are few moving parts. With adequate prefiltering to remove oil, desiccant replacement requirements are minimal.

(2) Heat Regenerative Dryers. Heat regenerative dryers utilize heat from an external source (either electric or steam) in conjunction with purge air to regenerate the offstream tower. By reducing the amount of purge air required to regeneration, the heat regenerative dryer operating costs can be outweighed by maintenance costs and downtime.

(3) Low-Temperature Regenerative. Low-temperature regenerative (heat pump) dryers utilize thermal energy from

the inlet air to heat the offstream tower for regeneration. No electric heaters or steam are used. This type of dryer provides the economy of refrigerated drying and the low-pressure dew-point capability of desiccant drying. Refrigeration cooling is used to remove most of the incoming moisture and to cool the onstream tower for high adsorption efficiency. This system saves energy, since the heat energy removed from the inlet stream is recycled by the refrigeration compressor and discharged to the offstream tower for regeneration. Stable pressure dew points down to minus 100 F are realized with this type.

e. Air Receivers. Air receivers are steel pressure vessels, constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, which are sized to dampen pulsations entering the compressor discharge line; to serve as a reservoir for sudden or unusually heavy demands in excess of compressor capacity; to prevent too frequent loading and unloading of the compressor, and to allow moisture and oil vapor carryover from the aftercooler to precipitate. Recommendations for receiver size and mounting are contained in TM 5-810-4. Drainage valves and piping, safety valves, and pressure gages must be installed in accordance with the Code.

2-46. STEAM TRAPS.

Steam traps are used to discharge condensate and air but not steam from a pipeline or heat exchanger. No single type of trap is ideal for every situation. The four major types of steam traps are thermostatic, float and thermostatic, disc/thermodynamic, and inverted bucket. These are discussed below. Orifice or impulse traps are also produced but operate by discharging steam continuously and are therefore not recommended. This waste, as well as the wasting of steam from defective or damaged traps, represents an energy loss that is not acceptable. Proper maintenance of steam traps is discussed in paragraph 5-40.

a. Thermostatic Steam Traps. Thermostatic traps can be further subdivided into balanced-pressure thermostatic traps, liquid expansion traps, and bimetallic traps. All three subtypes work by sensing the difference between steam temperature and cooler condensate temperature, utilizing an expanding bellows or bimetal strip to operate a valve head. They usually discharge condensate below steam temperature and therefore require a collecting leg before the trap to allow for some condensate colling. A balanced pressure thermostatic trap is illustrated in figure 2-116. Thermostatic traps are typically used in low and medium pressure applications such as steam radiators, submerged heating coils, and steam tracing lines.

b. Float and Thermostatic Steam Traps. Float and thermostatic traps (figure 2-117) are recommended for use

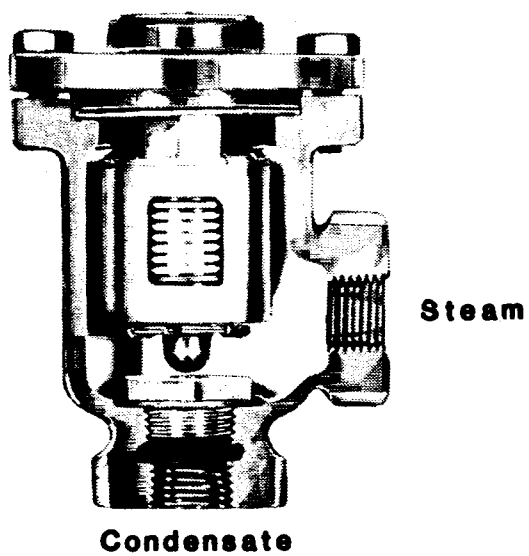


FIGURE 2-116. THERMOSTATIC STEAM TRAP

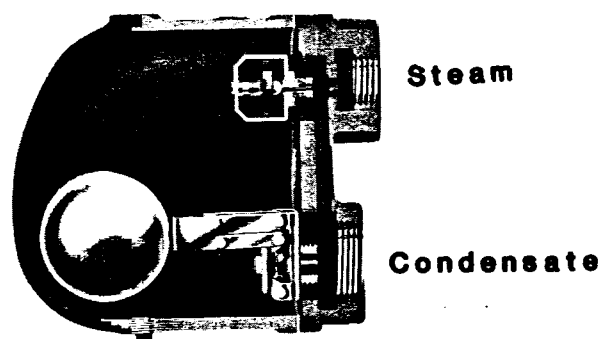


FIGURE 2-117. FLOAT AND THERMOSTATIC STEAM TRAP

wherever possible. Their valve seat is always under water, preventing any steam loss. The discharge is continuous and modulates with the condensing rate, and it is unaffected by changes in inlet pressure. A separate thermostatic air vent independently purges air, giving a fast startup, and discharges in parallel with the main valve seat without affecting its operation. Typical applications of float and thermostatic traps are air unit heaters, hot water heaters, heat exchangers and converters.

c. Disc/Thermodynamic Steam Traps. Disc/thermodynamic traps (figure 2-118) are widely used due to their small size, wide pressure range, one moving part, and resistance to water hammer and corrosion. Because operation of each model depends on the manufacturer's seat and disc design, results may vary widely. Many are prone to air-binding on startup, operate below steam temperature (causing waterlogging), have a relatively short life due to soft seat and disc materials, and contain a bleed slot which causes rapid cycling and steam loss. Properly designed disc/thermodynamic traps can overcome these problems and allow effective and efficient operation. They are typically used on high-pressure or superheated steam drip legs, steam trace lines, and unit heaters.

d. Inverted Bucket Steam Traps. Inverted bucket traps (figure 2-119) have been in existence for many years, and their low initial cost helps keep them popular, although in every application superior results can be obtained with another type of trap. They consume a small amount of steam in operation and can blow fully open if they lose their prime due to oversizing or a rapid drop in inlet pressure. Their discharge is intermittent, not continuous. Typical applications include high pressure indoor steam main drips and submerged heating coils.

2-47. PIPING SYSTEMS.

Piping (and tubing) systems are used in the central boiler plant to transport a wide variety of fluids, including among others water, steam, oil, natural gas, and compressed air. The following section is intended to provide a brief overview of some of the components and considerations which are involved in piping and tubing systems. The word piping in this manual can generally be assumed to mean both pipe and tube. Strictly speaking, however, there is a difference between pipe and tube, and this is discussed briefly in subparagraph c.

a. Design Codes. Design of boiler plant piping is generally governed by design codes and industry standards. The ASME Boiler and Pressure Vessel Code, Section I, which was discussed in paragraph 2-9 as it applies to boilers and accessories, also covers certain portions of the piping around the boiler. Much of the balance of the piping in a boiler plant is covered by the Power Piping Code,

ANSI B31.1. Some additional design codes and their applicability are given in table 2-8. These design codes generally specify the materials that may be used within their scope, how the piping sizes and thicknesses must be determined, how the pipe must be supported, what types of fittings, joints, and accessories may be used, and other provisions. Although these codes are written primarily for the pipe designer or engineer, a general knowledge of their provisions is useful to the operator as well.

b. Materials. Piping materials are generally specified by the design code under which the system is built. The most common piping material in the boiler plant is steel. Steel pipe is strong, relatively easily worked, and available in a wide variety of sizes to fit most applications of pressure, temperature, and fluid. Other piping materials which are used for specific applications include copper, stainless steel, cast iron, and plastic. Some common applications of the various materials are included in table 2-9.

c. Sizing. Standard specification of size is the primary difference between pipes and tubes. Pipe size is specified by Nominal Pipe Size (NPS) and Schedule. Tube size is given by outside diameter and wall thickness.

(1) **Pipe Size.** Nominal pipe size or NPS refers to the diameter of the pipe. Nominal pipe sizes range from $\frac{1}{8}$ inch up to at least 30 inches, in standard increments. The outside diameter for a given NPS is always the same, while the inside diameter varies depending upon the schedule. Schedule refers to the wall thickness and is generally listed as Schedule 40, Schedule 80, Schedule 160, etc. Earlier practice, which is still used on occasion, was to refer to schedules by designations such as Standard (STD), Extra Strong (XS), or Double Extra Strong (XXS). The dimensions and tolerances corresponding to the nominal sizes and schedules are established by ANSI standards. There is no easy way, other than referring to a chart, to determine the actual dimensions of a given nominal pipe size. For instance, 1 inch NPS, Schedule 80 pipe has an outside diameter of 1.315 inches, a wall thickness of 0.179 inch, and an inside diameter of 0.957 inch.

(2) **Tubing Size.** Tubing size is specified by Outside Diameter (OD) and wall thickness. Although tubing theoretically is available in almost any diameter, ranging from a few hundredths of an inch up to several feet, in practice, tubing in a boiler plant is limited to sizes of about $\frac{1}{8}$ inch to 1 inch. Tubing in common use in the boiler plant is generally either copper or stainless steel. The major exception to this rule is within the boiler itself. Boiler manufacturers generally use tubing rather than pipe, and for the most part use carbon or low alloy steel.

(3) **Determination of Proper Size.** Piping systems must be sized with regard to a number of criteria, including type and quantity of fluid to be transported, pressure and

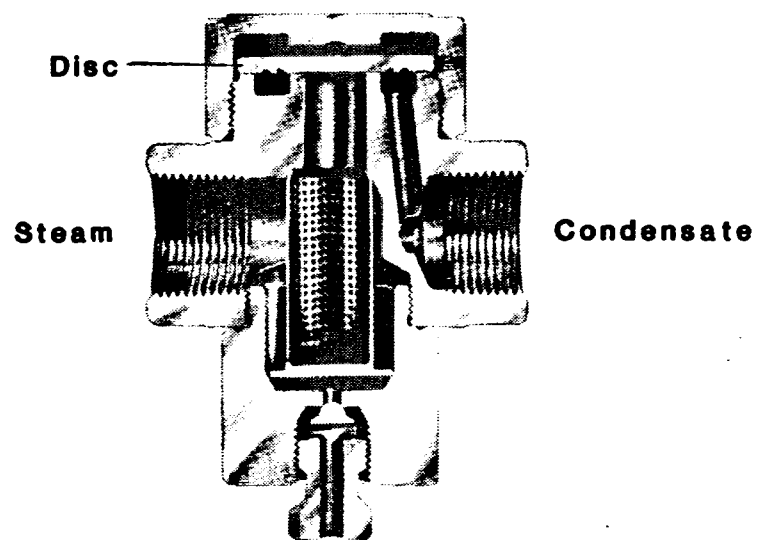


FIGURE 2-118. DISC/THERMODYNAMIC STEAM TRAP

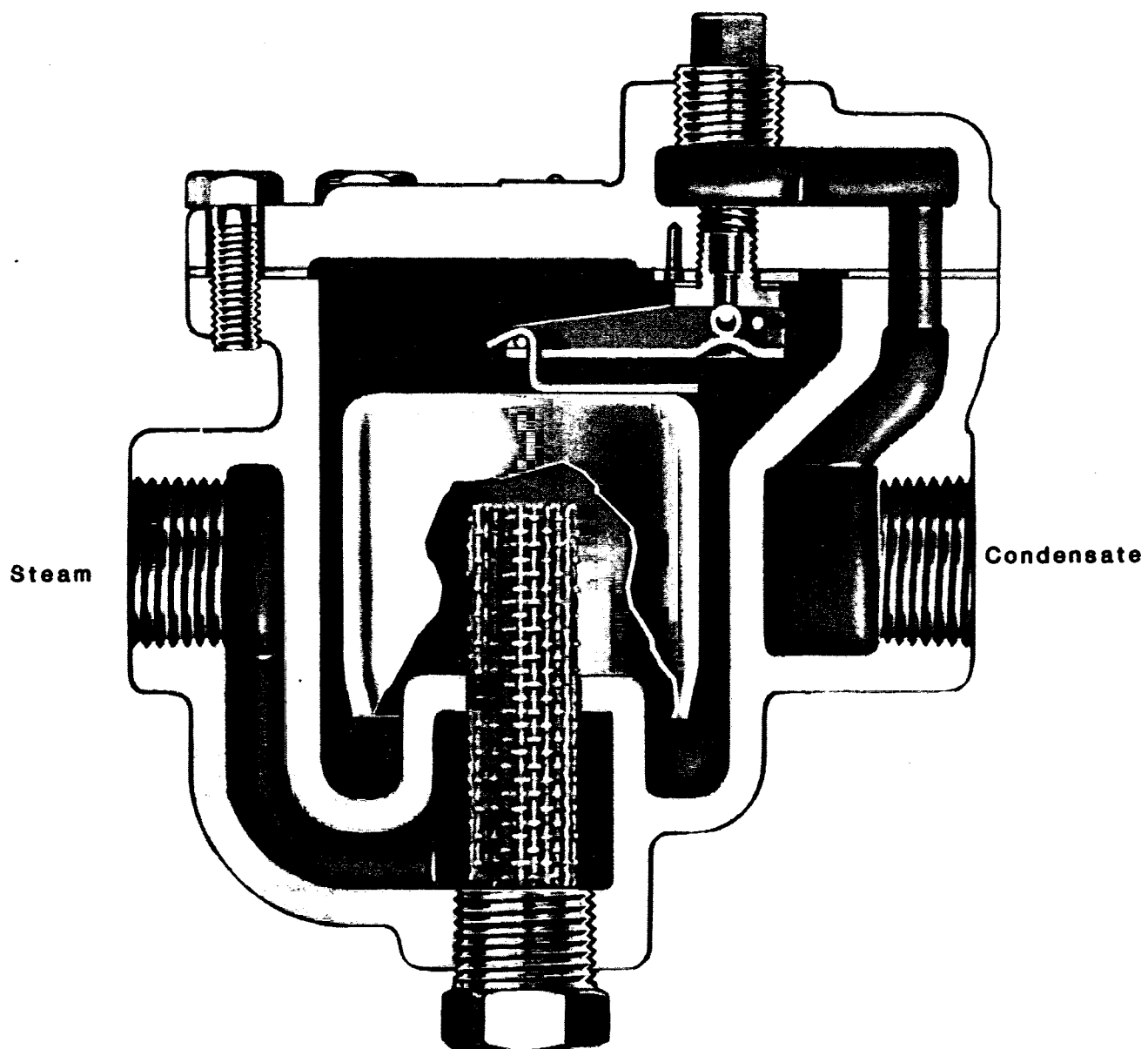


FIGURE 2-119. INVERTED BUCKET STEAM TRAP

Table 2-8. Piping Codes and Standards
For Boiler Plants

<u>Sponsoring Agency</u>	<u>Identification</u>	<u>Title</u>	<u>Coverage</u>
ASME	Boiler and Pressure Vessel Code - Section I	Power Boilers	All piping connected to boiler up to first (in some cases second) shut-off valves
	Boiler and Pressure Vessel Code - Section IX	Welding Qualifications	Qualifications for welders on power piping systems
ANSI	B31.1	Power Piping	All boiler plant piping beyond the jurisdiction of ASME BPV I.
	B36 Series	Iron and Steel Pipe	Materials and dimensions
	B16 Series	Pipe, Flanges, and Fittings	Materials, dimensions, stresses, and pressure/temperature ratings
	B18 Series	Bolts and Nuts	Bolted connections
ASTM		Testing Materials	Physical properties of materials specified in ASME and ANSI codes
NEMA	TU4 and SM20	Steam Turbines	Allowable reactions and movements on turbines from piping
NFPA	13, 15, et al.	Sprinkler Systems and Automatic Spray Systems	Piping for fire protection systems
AWS	D10.9	Qualifications of Welding Procedures and Welders for Piping and Tubing	Qualifications for welding of fire protection systems

Table 2-9. Typical Piping Material Applications

<u>Material</u>	<u>Typical Applications</u>	<u>Typical Joints⁽¹⁾</u>
Carbon Steel	High pressure steam, water, fuel oil, compressed air, and natural gas. Almost any fluid, with the exception of certain corrosive types, up to about 750F	Screwed, socket- or butt-welded, flanged
Low Alloy Steel	Superheated steam, up to 1000F	Welded
Stainless Steel	Chemical and corrosive applications ⁽²⁾ , steam above 1000F, instrument tubing	Socket- or butt-welded, flanged; tubing may use flared or compression fittings
Cast Iron	Floor and roof drains; water supply, sanitary piping; low pressure and temperature applications	Bell and spigot, mechanical groove-lock joints
Copper	Plumbing, potable water; instrument tubing	Soldered, flared, or compression fittings
Plastic (PVS, ABS)	Sanitary drains, non-potable water; miscellaneous low pressure applications	Solvent welded

NOTES:

1. Selection of proper joint must be based on design code.
2. Extreme care must be used in selection of proper alloys for corrosive service.

temperature conditions, allowable velocities, and pressure loss. These calculations can become quite sophisticated and are outside the scope of this manual. The pertinent design codes should be consulted for guidance.

d. Fittings and Joints. Pipe and tubing may be joined in a variety of ways, including threading, welding, flanges, a variety of mechanical coupling-type joints, soldering (for copper and brass), and solvent welding (for plastics). All of these methods are common, and the type used in a particular application is usually specified by the design code. In steel piping, high pressure systems such as steam or boiler feedwater commonly use welded joints, as do systems which are larger than approximately 2 to 3 inches in diameter. Smaller diameter systems in steel pipe may be threaded or socket welded. Flanges are often used when the piping must be disassembled periodically, for instance to perform maintenance on valves or other components. Fittings and flanges are available in materials and thicknesses to correspond to the pressure and temperature requirements of the piping system.

e. Pipe Supports. Proper support of piping systems requires sophisticated design calculations and is outside the scope of this manual. Some of the general criteria which must be considered in making these calculations are discussed below.

(1) **Allowable Stress.** The design codes for each application generally provide allowable stress levels for each material. These levels have been determined by experience to have adequate safety margin, and they must be adhered to. Allowable stress for a given material is a function of temperature and decreases at higher temperatures.

(2) **Expansion/Flexibility.** As the temperature of a pipe changes, the pipe moves due to expansion and contraction. Provisions must be made in the piping support system to accommodate this movement by providing piping flexibility through bends, expansion loops, or expansion joints. The required amount of expansion must be determined by calculating the stress level in the pipe and ensuring that it is less than the allowable stress.

(3) **Anchor and Supports.** An almost infinite variety of anchors, hangers, and supports may be seen in central boiler plants. A variety of hanger types has been standardized by the Manufacturers Standardization Society (MSS), and some of these are illustrated in figure 2-120. Custom-designed supports using structural steel shapes and standard hardware are also common.

f. Valves. Valves are available in a wide variety of types, materials, and pressure/temperature ratings to correspond to the system in which they are used and their purpose in that system. Some types of specialized valves are discussed elsewhere in the manual (Gage Cocks, paragraph 2-10; Safety Valves, paragraph 2-13; Boiler Outlet Valves, paragraph 2-14; Blowoff Valves, paragraph 2-15; Control

Valves, paragraph 2-25). Several additional common types are discussed below. Specific applications should be discussed with the manufacturers representative to ensure the correct body and internal materials, seat design, packing design and material, and other details.

(1) **Function.** Valves can serve many different functions in a piping system. Broad categories of valve function include: Isolation (on-off); Throttling (control); Backflow Prevention; Pressure Relief; and Regulation.

(2) **Gate Valves.** The gate valve is the simplest in design and operation and is commonly used in boiler plants. Gate valves are used where minimum pressure drop is important. They are employed where the valve will operate in a wide-open or fully closed position and is to be operated infrequently. Gate valves are not designed for throttling operation, and under prolonged use in a partially open position damage to the seat or disc may occur. A solid wedge type of gate valve is illustrated in figure 2-121.

(3) **Globe Valves.** The globe valve is used primarily for throttling or positioning to create a definite pressure drop. Globe valves are available in the common partial globe and seat contact type, the small needle type, and numerous variations such as top-guided, post-guided, angle, Y pattern, fluted, and cage-guided. Because of their inherent ability to exhibit repeatable flow curves, they are the most commonly used type of valve for control valve application. Globe valves can also be used in on-off service where pressure drop in the fully open position is not of primary importance. Normally, globe valves are installed with the flow under the disc, but in certain cases where it is desirable to have line pressure assist in maintaining seat closure, flow may be directed over the disc. In motor- and air-actuated valves, this flow direction is very important in sizing the actuator. A standard single port globe valve is illustrated in figure 2-122.

(4) **Plug Valves.** The plug valve is a refinement of the earliest known valve, the spigot. Basically, it is a 90-degree rotation from open to closed position of a tapered inner valve. The downward thrust of the plug taper exerts a compression load on the side wall, thus ensuring a continuous circumferential sealing surface. Like the gate valve, it is used primarily in on-off service only. The plug valve has the added benefit of bubbletight sealing, thus making it ideal for gaseous service. In addition, because of its large unobstructed flow passage, the plug valve is ideally suited for sluffy service. A typical plug valve is illustrated in figure 2-123.

(5) **Butterfly Valves.** Butterfly valves have been used in industry for decades, performing well-defined tasks in which they show distinct advantages over other valve types. Some butterfly valve designs can provide dependable bubbletight shutoff, and others are ideally suited for throttling or control applications, having an equal

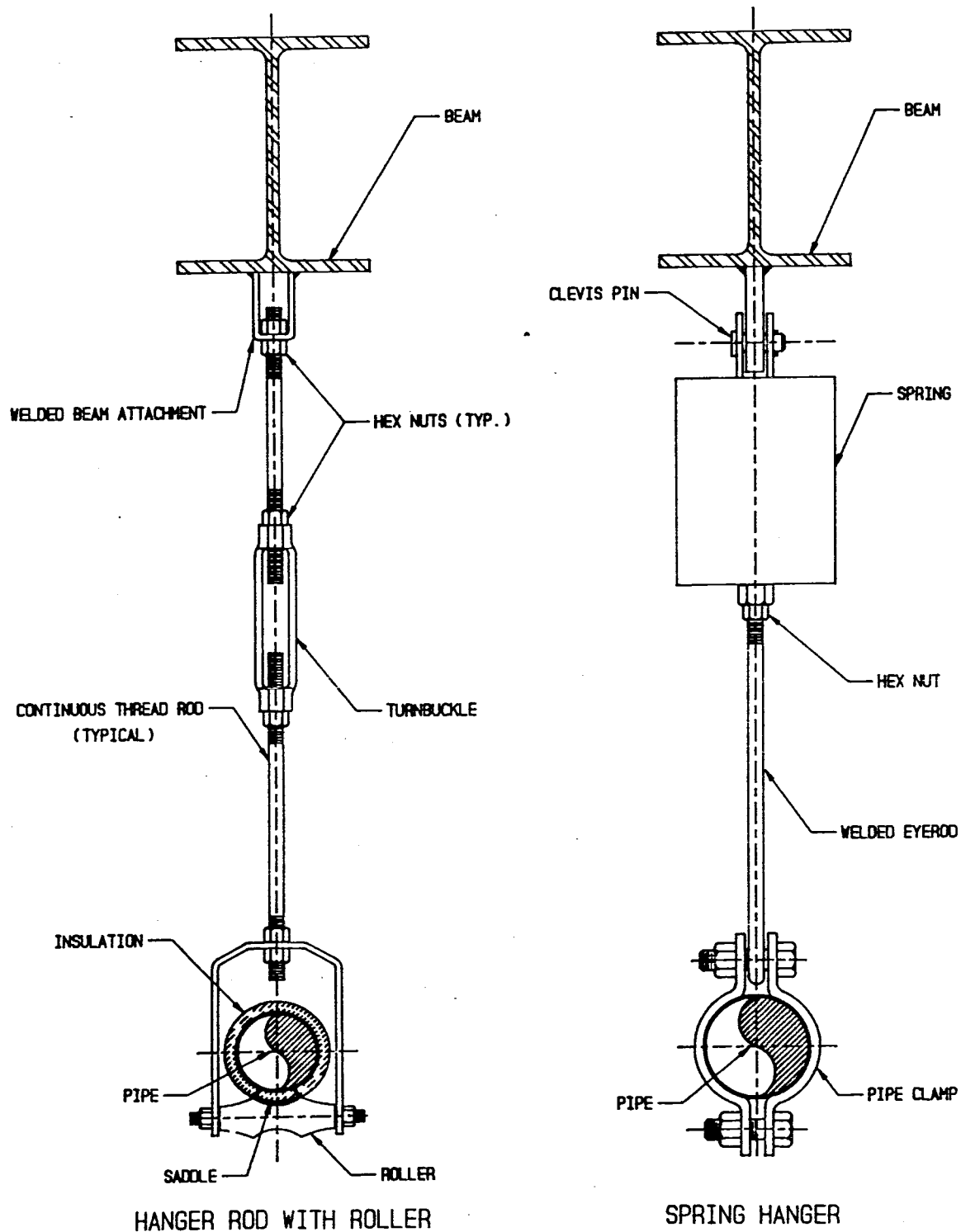


FIGURE 2-120. STANDARD HANGER TYPES FOR PIPING SYSTEMS

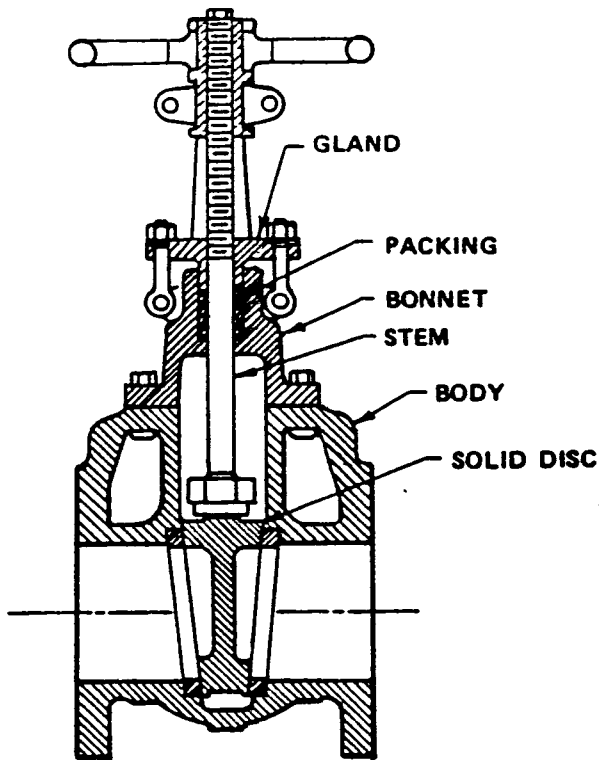


FIGURE 2-121. SOLID WEDGE DISC GATE VALVE

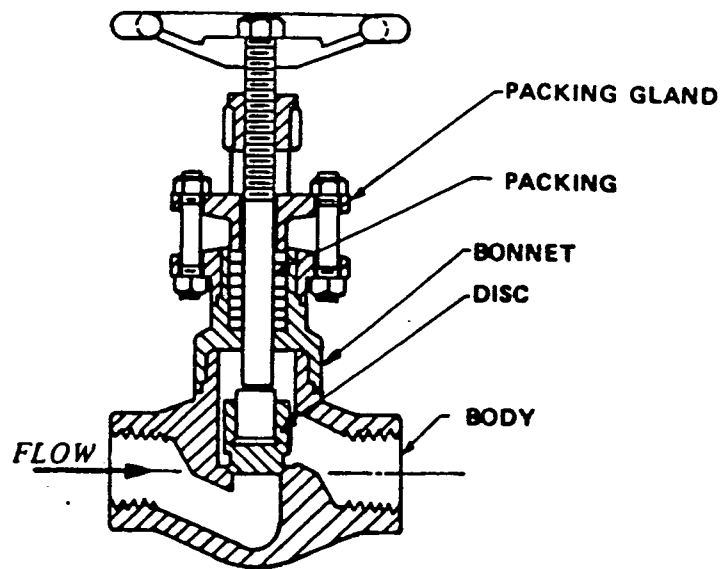


FIGURE 2-122. SINGLE PORT GLOBE VALVE

percentage flow characteristic. Butterfly valves are quick opening and highly efficient, can be operated manually or automatically, and can be used in handling a variety of media, including liquids, solids, slurries, gases, and vapor (steam). Figure 2-124 illustrates a typical butterfly valve.

(6) **Check Valves.** Check valves are designed for use in a piping system where protection against the reversal of fluid flow is desired. During operation, liquid or gas pressure will move the disc off the valve seat and allow fluid to flow through the valve with minimum pressure drop. If the fluid flow ceases or reverses direction, the reverse fluid flow and design of the disc assembly will force the disc against the seat to prevent fluid backflow. The disc weight, seat configuration, and internal spring assistance (if provided) all contribute to the ease with which

the disc opens or closes and to a leaktight seal when in the closed position. Check valves can be obtained in a wide variety of styles to fit specific applications. Two of the more common types (swing check and spring loaded lift check) are illustrated in figure 2-125. g. **Insulation.** Insulation is used to reduce dheat loss from hot piping, eliminate condensation, reduce heat gain on cold piping, and provide personnel protection. Insulation types typically used in central boiler plant piping systems include fiberglass, mineral wool, and calcium silicate. Jacketing or vapor barrier is usually incorporated over the insulation to protect the insulation material. Common jacket materials include aluminum, fiberglass cloth, and various other fabrics.

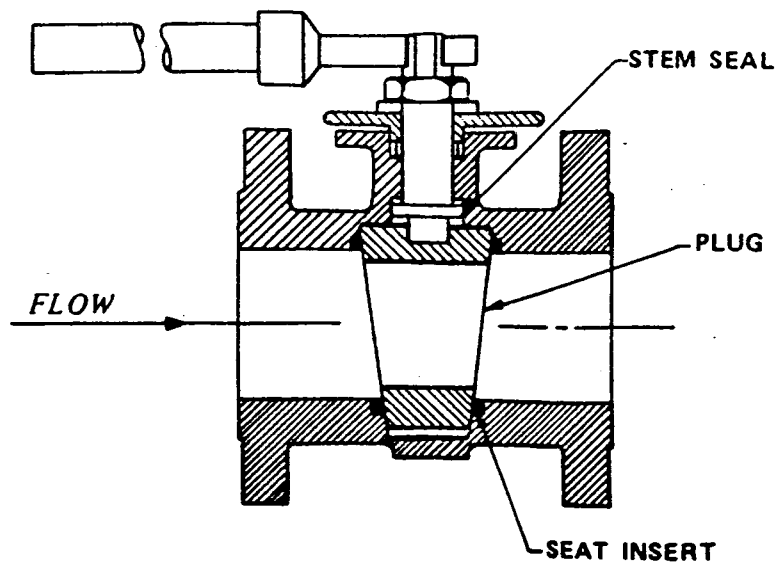


FIGURE 2-123. NON-LUBRICATED PLUG VALVE

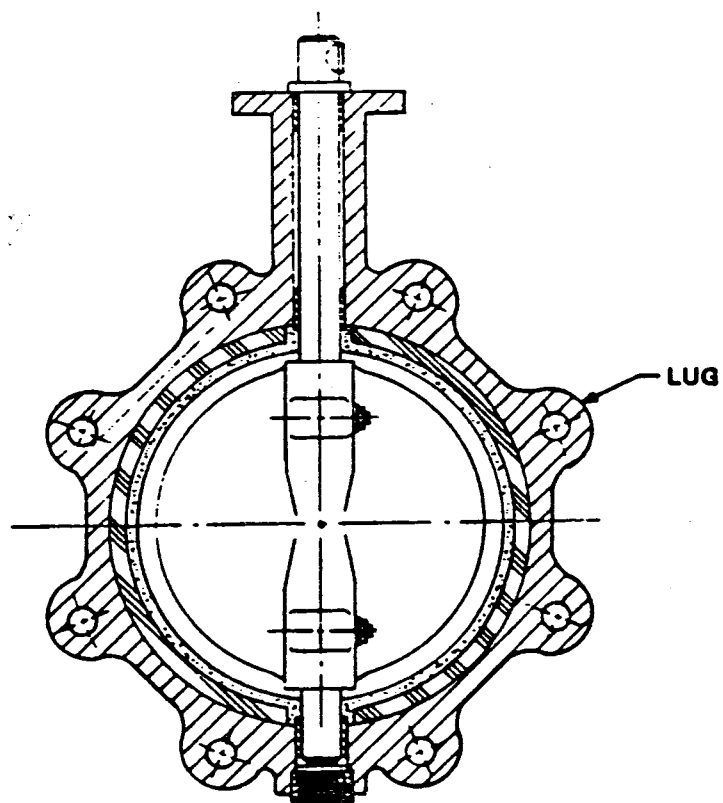


FIGURE 2-124. BUTTERFLY VALVE

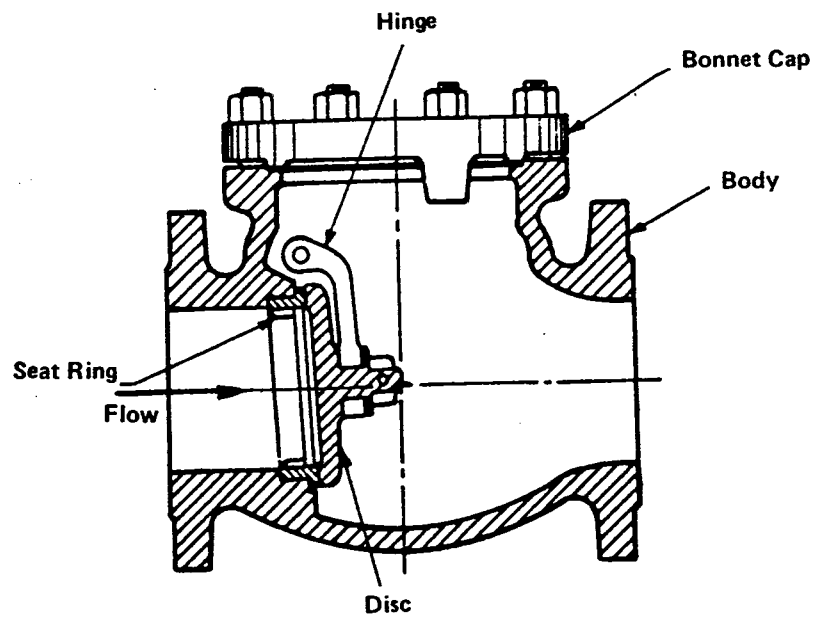


FIGURE 2-125A. SWING CHECK VALVE

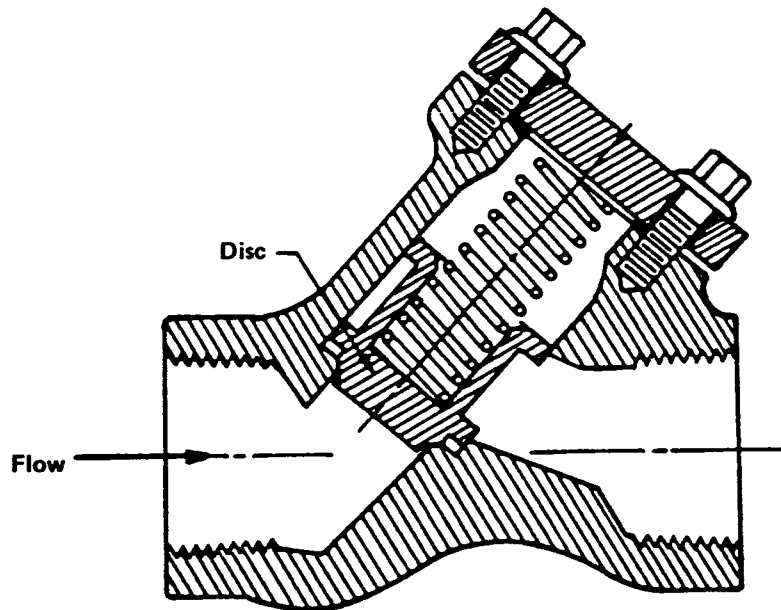


FIGURE 2-125B. Y TYPE SPRING LIFT CHECK VALVE